THE DEVELOPMENT OF A GLOBAL LNG MARKET

Is it Likely? If so When?

James T. Jensen

OXFORD INSTITUTE FOR ENERGY STUDIES

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Professor Jonathan Stern
Director of Gas Research

CONTENTS

LIST OF FIGURES

LIST OF TABLES

SUMMARY AND CONCLUSIONS

In its title, this study raises two questions: 'The Development of a Global LNG Market – Is it Likely? If So, When?' The answer to the first question must be, 'It depends on the definition of "global LNG market"'. But perhaps surprisingly, the answer to the second question – depending on the definition – might be, 'It is already here.' The reason the second answer may come as a surprise is that the global LNG market shows very little family resemblance to its two ostensible parents – the world oil market and the various liberalised onshore natural gas markets. But while it has clearly changed the traditional regional isolation of the gas industry and thus deserves recognition as a 'global market', it should not be expected to behave in the same way as either world oil or onshore gas.

The LNG market is not – nor will it ever be – as flexible as the world oil market. The high costs of LNG transportation still make it difficult to move the commodity physically over long distances. Only when there is surplus capacity in liquefaction plants and tankers can LNG compete in distant markets. And in those cases it competes on a marginal cost basis where the investor recovers less than his originally planned return on investment.

Nor is LNG likely to achieve the competitive commodity status that the liberalised gas markets of North America, the UK and increasingly the Continent have produced. The long-term contract in LNG has been the vehicle for sharing the large up-front investment risks that characterise LNG projects. The short-term LNG market, while growing, still remains at less than 9% of total trade. But more significantly, no new LNG train has been launched without at least some long-term contract coverage. Thus it appears that the long-term contract in LNG will remain a mainstay of international LNG trade even if it has all but disappeared in onshore North America. The concept of using financial derivatives to manage risk on these multi-billion dollar projects is probably unrealistic.

Nonetheless, the declining costs of delivering LNG, the growing diversity of supply sources and a loosening of the traditional rigid industry structure, have created a system which can transmit price signals freely between previously isolated regional gas systems. An active arbitrage market has developed in the Atlantic Basin where shipments from Trinidad or Nigeria have been diverted either to the USA or Spain depending on price. And the fact that the Middle East – in particular, Qatar – has become a swing supplier to both the traditional gas markets in Northeast Asia and the growing markets in the Atlantic Basin means that price signals are transmitted between Asia and the Atlantic Basin, as well. Thus it is not the magnitude of the physical flows between regions that defines the global LNG market, but the fact that small shifts in sources and destinations can provide a basis for international price arbitrage.

But because the volumes of LNG in short-term trading are not that large compared to the size of the markets they serve, price arbitration will have its limits in actually establishing long-term price equilibrium among different gas market regions. In each market, LNG will add to supply and thus influence the supply/demand/price relationships. But it is unlikely in fact that they will determine prices in most markets. If that more ambitious goal is the definition of a 'global gas market', LNG may well not live up to expectations.

This study has come to a number of conclusions about the future of the global LNG market that are discussed in the body of the report. Among the major conclusions are:

1. North America will emerge as the largest target for LNG imports.

The combination of growing gas demand – particularly for power generation – in the face of deteriorating prospects for traditional North American supplies will provide the stimulus for this growth. Canada has been a major incremental contributor to US supply, but now Canada's own supply problems together with its own growing demand may force it to reduce its exports to the USA.

2. Europe may not be far behind as a potential LNG importer.

Gas supplies for much of Europe are now in surplus, but that is expected to be short-lived as growing demand will encounter declining prospects for North Sea production. To some extent the outlook for LNG will depend on how some of the present competition between pipelines and LNG is ultimately resolved.

3. The Northeast Asian markets and Pacific Basin supplies that have traditionally dominated the trade will become relatively less important in the near future.

With the emergence of the larger North American and European gas markets as major LNG importers, the balance of LNG growth appears to be shifting to the Atlantic Basin. Middle East supplies are now the fastest growing. China and India represent new Asian growth markets for LNG, but their future rate of development is far from clear

4. The Middle East should become the fastest growing source of supply.

Qatar has been aggressive in developing LNG projects from its portion of the world's largest gas field. While Abu Dhabi and Oman are also suppliers, the LNG potential from Iran is very large and that country is actively pursuing LNG possibilities.

5. In Africa, Algeria and Nigeria are already major players in LNG and Egypt is poised to join them.

Libya may be about to revive its old LNG trade and in West Africa, both Angola and Equatorial Guinea are actively exploring LNG options.

6. The long-term contract will remain as the dominant relationship between buyer and seller, but contracts will become much more flexible and short-term volumes will continue to increase.

Despite the growth of the short-term market, it remains a small proportion of total trade. LNG is by its nature highly capital-intensive with substantial financial risks. Since no project developer has been willing to launch a new project without some contract coverage to help manage that risk, the long-term contract will remain as the mainstay of the LNG business.

7. The concept that financial derivatives can be used to hedge project risk on long-term, multi-billion dollar LNG investments

has been largely discredited with the failure of the large merchant traders who originally promoted the idea.

8. The ability of buyers to assume project risk has deteriorated in those markets that have restructured so that risk has effectively migrated upstream.

Early LNG buyers were either monopoly government companies or regulated utilities. They were able to honour the traditional take-or-pay volume obligation based on an independent pricing clause in the contract, even if it were not as favourable as when they first signed. In the restructured industry where companies are exposed to market risk, most buyers cannot assume a volume risk without a market-responsive pricing clause. Thus the sellers are more directly exposed to market risk than they were traditionally.

9. This creates pressures for suppliers to integrate downstream as they have traditionally done in oil.

The first symptom of this trend is the development of 'self-contracting' by suppliers – that is writing contracts with their own marketing affiliates. While this may give the appearance, together with the companies' ordering uncommitted tankers, that the market is moving towards short-term trading, this can be misleading. To the extent that the companies continue to serve their own established terminals on reasonably orderly tanker schedules, the self-contracting may be just a disguised form of traditional dedicated operations

10. The large capital requirements of the business, together with the risks involved, will favour the 'super majors'.

11. Nevertheless, selected opportunities for smaller companies to play a 'niche' role will remain but it is not a business for the faint of heart or the undercapitalised.

1. THE LNG INDUSTRY – AN OVERVIEW

The low density of natural gas makes it more costly to contain and transport than either oil or coal. Prior to the development of liquefied natural gas (LNG) technology, the transportation of natural gas was limited to movements that could be served by pipeline. Gas was unable to utilise that mainstay of international oil trade – marine transportation. The development of LNG has changed all that, and with the improvements in technology and costs, gas is rapidly becoming an internationally traded commodity.

1.1 The Basic Elements and Cost Structures

Liquefaction depends on the refrigeration of natural gas to cryogenic temperatures (approximately minus 260°F) where it becomes a liquid at atmospheric pressure and occupies a volume that is 1/600th that of the fuel in its gaseous form. The product can be stored in heavily-insulated tanks or moved overseas in special cryogenic tankers. But the special processing and containment requirements to transport gas as LNG come at a significant cost.

An LNG project represents a 'chain' of investments whose ultimate success is at risk to the possible failure of its weakest link. The chain consists of four (occasionally five) links – field development, in some cases a pipeline to the coast, the liquefaction facility, tanker transportation and the receipt/regasification terminal. Each element is capital-intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete. Hence breakdowns and delays in any part of the chain have adversely affected capital recovery and project internal rate of return (IRR).

The liquefaction plants consist of processing modules called 'trains'. Train sizes tend to be limited by the size of the available compressors. Early train sizes tended to be about 2 million tons and a greenfield facility would often require three trains to be economic. Recent improvements in compressors have made it possible to design larger trains to benefit from economies of scale. The largest current operating trains are about 4 million tons, but Qatar is considering trains that could reach 7.8 million tons.

The cryogenic tankers are much more costly than oil tankers, both because of the low density of the product and the need for insulation and low temperature metallurgical designs. The current typical size of an LNG tanker is 135,000 to 138,000 cubic metres of cargo, but designs of up to 250,000 cubic metres are under study.

The centres of population in large Asian LNG importing countries – Japan, Korea and Taiwan – are coastal, which makes it easy to deliver LNG without serious concern for onward pipelining. For markets with an established pipeline grid, such as the USA or Europe, the introduction of LNG can easily alter the geographic pricing relationships (basis differentials) among different points on the pipeline system. This 'basis risk' is a factor to consider in determining how much LNG a regional market can absorb before it affects the market pricing structure. In new markets, such as India or China, the costs of reaching the interior of the country with regasified LNG delivered by pipeline can seriously affect the competitiveness of the fuel.

Table 1.1 illustrates the balance of capital expenditures (CAPEX) and margins for a hypothetical LNG project. It uses a West African source supplying a US Gulf Coast regasification terminal (at Nigeria's distance from the US Gulf Coast) and designed for two 3.3 million ton trains. This illustration has a total CAPEX of $5 billion and could deliver to the Gulf Coast for a cost-of-service[1] of $3.39. In the illustration, 58% of the

Table 1.1: Elements of an LNG Delivery System

	Capex	Cost Of Service
Field Development (Varies)	$1.3 Bn	$0.80
Liquefaction	$1.6 Bn	$1.22
Tankers (10 @$160 Mn)	$1.6 Bn	$0.98
Regasification (Varies)	$0.5 Bn	$0.39
Total	$5.0 Bn	$3.39

Basis: Greenfield Facility, Two 3.3 Mmt Trains, 6,200 Nautical Miles (Roughly Nigeria to the US Gulf). Requires About 280 Bcm of Reserves to Support a 20-Year Contract

CAPEX are located in the host country, 10% are located in the consuming country and the remaining 32% are required for the tankers.

Because of its special processing and handling requirements, the costs of moving natural gas are significantly higher than the costs of moving oil or even waterborne coal. And the relative costs of moving gas or oil by pipeline or by tanker differ substantially, as well. This influences regional interfuel competition and thus natural gas markets.

The costs of pipelining natural gas benefit substantially from economies of scale, since large diameter pipelines are not that much more expensive to lay than smaller lines but carry much greater volumes. Pipeline costs rise linearly with distance, but LNG – requiring liquefaction and regasification regardless of the distance travelled – has a high threshold cost but a much lower increase in costs with distance. Thus shorter distances tend to favour pipelining, but longer distances favour LNG. These relationships are illustrated in Figure 1.1.

1.2 History of World LNG Trade

The first tanker shipment of LNG took place from Lake Charles,

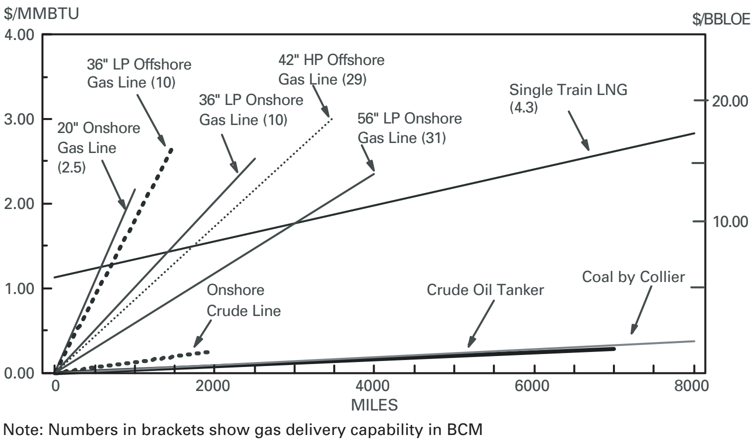


Figure 1.1: Illustrative Costs of Gas, Oil and Coal Transportation

Source: Author's estimates

LA bound for Canvey Island in the UK in 1958 aboard the experimental vessel, the Methane Pioneer. It was followed in 1964 by the first commercial trade – the CAMEL project to deliver Algerian gas to the UK and France. By 1969, three more trades had started – an additional delivery from Algeria to France, one from Libya to Italy and Spain, and one from the Cook Inlet of Alaska to Japan, the first Pacific project.

While the first deliveries from Algeria were comparatively short hauls to Europe, the USA entered the market first in 1972 when deliveries started for a small Distrigas (Cabot) project at Everett, MA. Deliveries began in 1978 for the much larger contracts by El Paso Natural Gas to Columbia Gas for Cove Point, MD and Southern Natural at Elba Island, GA. They were followed by the startup of the Trunkline project for Lake Charles, LA in 1982.

The development of the early US projects took place during a period of unprecedented change in international energy markets. This included the two oil price shocks, the widespread nationalisation of the international oil companies' concession areas within OPEC, and the restructuring of the North American gas industry. While LNG imports into Europe continued to increase, the North American trade nearly collapsed, thereby blunting what was expected to be a substantial growth in Atlantic Basin trade.

With the substantial slowdown in interest in LNG in the Atlantic, the balance of interest shifted to the Pacific as Korea and Taiwan joined Japan as importers. Figure 1.2 shows the growth of imports by region, indicating the strong contribution of Asian markets to demand. Between 1975 and 1996, the Asia Pacific demand increased by an average of 3.31 BCM per year (about 2.4 MMT, slightly more than the capacity of the typical LNG train at the time). In contrast, Europe and the United States increased only 0.76 BCM per year. Since 1996 Atlantic Basin markets have begun to take off, so that average Atlantic growth has been 3.97 BCM per year compared to Asia's 4.22 BCM. These are roughly equivalent to the capacity of a more modern 3 MMT train.

With the continuing growth of Asian markets, the principal suppliers were from the Asia Pacific region – Indonesia, Malaysia, Australia and Brunei. (See Figure 1.3) The first Middle East project from Abu Dhabi dates back to 1977, but there was no

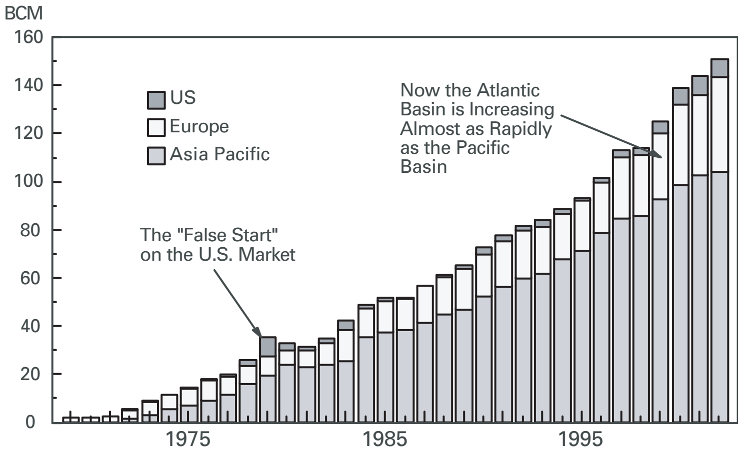


Figure 1.2: Growth of LNG Imports by Region

Source: Cedigaz

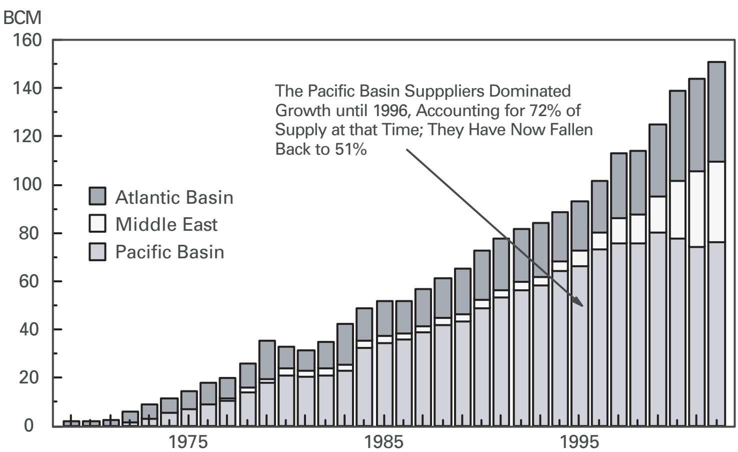


Figure 1.3: Growth of LNG Exports by Source

Source: Cedigaz

significant expansion until the major new projects from Qatar and Oman in the late 1990s. Similarly, the slow growth of European and US markets until recently limited the Atlantic

Basin suppliers to Algeria and Libya. With the startup of new liquefaction plants in Trinidad and Nigeria in 1999 the Atlantic Basin suppliers are now poised for substantial growth.

Table 1.2 shows the balance of LNG importing countries for the year 2002, showing the dominance of the Pacific Basin trade. Japan alone accounts for nearly 60% more demand than the entire Atlantic Basin combined. Table 1.3 provides similar information about the exporting countries.

Table 1.2: LNG Imports by Country – 2002

	BCM		BCM
Japan	72.74	Spain	12.26
Korea	24.06	France	11.54
Taiwan	7.00	USA	7.11
		Italy	5.70
		Turkey	5.35
		Belgium	3.30
		Greece	0.50
		Portugal	0.43
Pacific Basin	103.80	Atlantic Basin	46.19

Source: Cedigaz

Table 1.3: LNG Exports by Country – 2002

	BCM		BCM		BCM
Indonesia	34.33	Qatar	18.59	Algeria	26.88
Malaysia	20.52	Oman	7.96	Nigeria	7.84
Australia	10.03	Abu Dhabi	6.85	Trinidad	5.32
Brunei	9.14			Libya	0.63
Alaska	1.70				
Transshipment	0.20				
Pacific	75.92	Middle East	33.40	Atlantic	40.67

Source: Cedigaz

Indonesia has been the world's largest supplier, but Qatar in the Middle East and both Trinidad and Nigeria in the Atlantic Basin are increasing their exports substantially. Egypt, while not yet an exporter, has two LNG facilities under construction and seems destined to become a major LNG supplier.

1.3 Forces Driving the Renewed Interest in LNG

A number of factors have combined to stimulate the renewed interest in LNG:

- Combined cycle power generation for growing electric power markets
- The effects of technology on cost reduction making previously uneconomic trades attractive
- Environmental concerns
- The embrace of gas by previously 'gas poor' economies
- The growing concern for traditional supplies in the face of growth
- The 'stranded gas' phenomenon

The thermal efficiency of traditional steam boilers for power generation is limited thermodynamically to about 38 per cent. But by placing a high-temperature gas turbine on the front end, and then recovering the high temperature turbine exhaust for steam generation in a heat exchanger, the combination – a 'combined-cycle' (or CCGT) unit – can achieve thermal efficiencies approaching 60 per cent. In addition these units have relatively low capital costs, come in smaller, market-friendly sizes and have short planning lead times. The turbines are similar to those on jet aircraft and thus the fuel must be either natural gas or a very high-quality distillate product. CCGT units have become the power generation systems of choice for electric markets around the world.

In the past five to ten years, technology has made it possible to design new LNG liquefaction facilities and tankers for substantial cost reduction. Hence, trades that once seemed uneconomic have become attractive.

The liquefaction cost reduction has been due to a number of factors. With more activity and more design constructors, plants have benefited from greater competition and higher productivity. The maturing of the industry with diversified supply sources has led to less concern for building in redundancy – commonly called 'gold plating' – to ensure operating reliability. But substantial improvements have come from increasing plant sizes and the resulting economies of scale. Expansion by means of one modern 4 MMT liquefaction train can cut the costs of liquefaction by about 25% compared with the two 2 MMT trains that were common ten years ago.

Tanker costs have come down as well. Perhaps more of this improvement has been the result of greater activity and the resulting competition among shipyards for business. But increased tanker sizes have also improved economics, although the scale improvements are not as marked since the size increases have been less dramatic. A new 140,000 cubic metre tanker could probably cut costs by about 5% relative to the 125,000 cubic metre tanker of ten years ago.

Nigeria provides an illustration of the evolution of today's optimism about LNG economics. In the mid-1990s, after thirty years of off-and-on industry discussions of an LNG project, a consortium of Shell, AGIP, Elf and Nigerian National Petroleum Company, started negotiations on what has become the Bonny LNG project in that country. Initially the sponsors could not demonstrate economic feasibility for a project destined for Italian and US markets. But by taking very low-cost options on seven laid-up LNG tankers at a time when the price of new builds was at an all-time high, they cut project costs enough to make it economic.

Figure 1.4 illustrates the economics that a new Nigerian greenfield project destined for the US Gulf Coast might have faced in 1998, given the designs, costs and market price expectations of the period. As is evident, the project was a non-starter since the initial netback from the expected Gulf Coast market price to the inlet of the liquefaction plant was negative (-$0.21). Figure 1.4 then traces the improvements in netback as a result of using current cost estimates for the original design, as well as the design improvements in plant economics from increasing plant sizes – two 3.75 MM ton trains, instead of three 2.5 MM ton trains. The common mid 1990s view of relatively low prices for 2010 – represented by the 2001 *Annual Energy Outlook* of the EIA – has been changing. The 2004 AEO price projection was 32% higher for 2010.

The result of these improvements is striking. From a netback of -$0.21, the changes have boosted the netback into the plant gate to $1.04.

Environmental concerns are clearly a driving force in developing interest in natural gas and in LNG. Not only is gas essentially

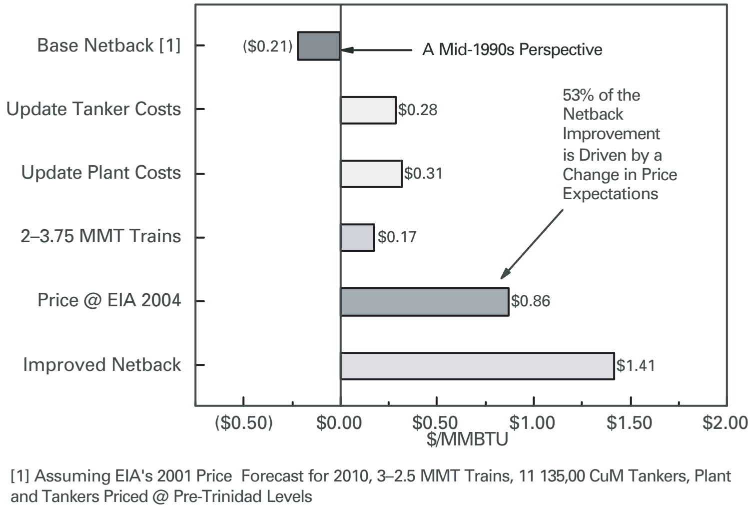


Figure 1.4: The Evolution of Optimism About LNG Imports

Source: Author's estimates

free of sulphur and particulate matter, but the increasing concern for global warming also benefits gas. Not only does gas have a higher hydrogen-to-carbon ratio, minimising CO_2 emissions, but CCGT's higher thermal efficiency requires less fossil fuel per MWH generated. By comparison with a coal-fired boiler, gas-fired CCGT units can cut CO_2 emissions by about 40 per cent.

The underlying economic growth of some of the emerging market countries, when coupled with the advent of gas-fired CCGT power generation, has made them targets for LNG imports where they were not previously able to justify natural gas. India, China and Turkey are prime examples of this group.

But some economies that have utilised natural gas are now interested in natural gas to offset problems with traditional supply or to provide supplier diversification. This is certainly the case in the USA. And it is also the case in the UK. As recently as 1998, when the Interconnector Pipeline was inaugurated to link Bacton in the UK with Zeebrugge in Belgium, the UK was expected to be a major exporter to the Continent. Now with declining prospects for North Sea production, the UK is about to develop LNG imports and may possibly emerge as a major competitor to the United States for LNG supply. In a somewhat different motivation, Spain has attempted to diversify its heavy reliance on one country – Algeria – by entering LNG import markets in a major way.

Another factor that has led to the higher interest in LNG is the emergence of concern for 'stranded gas'. At one time, companies searching for oil in international concession areas treated a gas discovery as a 'dry hole' and abandoned further effort in the area. Now with the possibility of major oil discoveries narrowing in many areas and with a mounting inventory of gas discoveries, companies are much more willing to concentrate on gas development possibilities.

Notes

1. 'Cost-of-Service' describes a price based on costs plus a reasonable return on investment.

2. THE ROLE OF THE LONG-TERM CONTRACT IN TRADITIONAL LNG SALES

2.1 The Sale and Purchase Agreement (SPA) and its Risk-assuming Obligations

The traditional LNG project featured a carefully structured system of risk sharing among the participants. Central to the project was the long-term contract between buyer and seller for LNG – known as the Sale and Purchase Agreement or SPA. Early contracts were typically for twenty years duration, although longer contracts were common. The point of delivery might be either f.o.b or ex ship, depending on which party assumed the tanker transportation responsibility, but in either case the operation of the receipt and regasification terminal was downstream of the point of delivery and thus outside the scope of the contract. Tankers might be owned by either buyer, seller or independent shipowners, but traditionally were dedicated to the specific trade, usually for the life of the contract.

The risk sharing logic of the contract was embodied in the phrase 'the buyer takes the volume risk and the seller takes the price risk'. Hence most contracts featured take-or-pay provisions to assure buyer offtake at some minimum level and a price escalation clause to transfer responsibility for energy price fluctuations to the seller. The early contracts viewed oil, not gas, as the competitive target and thus 'price risk' in the indexation clauses was principally defined in oil terms, a pattern that persists in some markets to this day.

In the original pattern of LNG project development, nearly all buyers were either government monopoly or franchised utility companies from OECD countries. Sellers were typically either major oil companies or national oil companies of producing countries. Hence, financial creditworthiness for the project was usually not an issue. This enabled LNG projects to obtain favourable financing, giving them a debt-equity ratio and cost of capital more nearly resembling utility financing than that of corporate equity.

Since most of the purchasers were regulated utilities or government monopoly companies, they were effectively able to lay off some of the market risk to their end use customers. Once a contract was approved by the regulators or government overseers, the price and volume terms became part of the regulated resale rate structure and end users picked up the tab.

This pattern has been changing. Interest in LNG has spread to smaller buyers, such as independent power projects, whose creditworthiness may be in question. And the restructuring of the gas industry often limits the ability of buyers to lay off contractual risk. Hence the financial risks of the newer projects are often inferior to those that marked the early days of the industry and they may be less able to obtain favourable financial terms.

Both field development and liquefaction investments in the producing country have commonly been based on significant gas discoveries. Hence companies holding the relevant exploration licences have initiated most of the projects. The discoveries have been dedicated to the contract to ensure a reliable supply for the project. Since the goal has been to guarantee full deliverability over the life of the contract, the deliverability 'break' when production rates can no longer be sustained at contract delivery levels is important. For a twenty-year contract, for example, it might take as much as 28 years of reserve support to provide such a supply guarantee. A 28-year RP ratio represents a conservative rate of field depletion with obviously adverse economic consequences for field economics. More flexible access to additional reserves near the liquefaction facility might well enable the project to utilise higher depletion rates.

The project developers have usually been joint ventures of several companies, bound together in a 'shareholders' agreement' or a 'joint venture agreement', depending on the nature of the licence, with one of the group appointed as the operator. The effect of this structure is that companies have operated as if they were shareholders in a corporation, rather than as independent and competitive corporate entities. Thus marketing has usually been done by the venture rather than by the individual partners, a system which has reduced the number of competing marketers. Competition exists but it has been between projects rather than among the individual participants in the venture.

2.2 The Rigidities Imposed by the System

The SPA envisioned a system in which particular trades were essentially self-contained, involving a specified liquefaction facility as the source of the LNG and dedicated tankers to shuttle between the specific plant and its destination. The bilateral nature of the trades made it unnecessary to build in design flexibility for the tankers to serve other ports, and questions of interchangeable gas quality were largely ignored. Even today some terminals cannot accept cargoes from some liquefaction plants because they fail to meet the quality specifications of the new terminal. This is a major issue in both the USA and UK, where special nitrogen 'ballasting' may be required to accommodate some of the cargoes.[1]

The volume obligation in the long-term contract was embodied in the take-or-pay clause, and commonly obligated the buyer to take a minimum of 90% of his annual contract quantity. The contract was designed to ensure that the debt service on the financing could be met and thus, ideally, would provide for level cash flow over the contract period. But real markets seldom behave ideally. Most markets grow so that a volume that is keyed to current demand will be inadequate to meet future requirements several years down the road. Hence, most contracts feature a 'plateau' volume and a 'ramp-up' period for the customer to grow into his volume commitment. Markets may also have distinct seasonal swings if they have a large proportion of temperature-sensitive load. This is the case in Korea, for example. And, the market uncertainties surrounding economic cycles are another source of demand variability.

Buyers and sellers have historically found ways in which to adapt the rigid contract structures to the realities of a somewhat uncertain market. Well before the restructuring of the gas industry in North America and the UK created active gas spot markets, LNG buyers and sellers – by mutual agreement – utilised short-term markets to adjust over and under commitments among themselves. These transactions, never a large part of total LNG trade, were usually arranged bilaterally and were better described as 'short-term sales' rather than 'spot sales'. One of the most adventurous of the buyers has been Kogas in Korea. Its seasonal market has been difficult to accommodate within the constraints of the typical 90% take-or-pay limitation and it has recently gone heavily into the short-term market for peaking requirements.

In the traditional contract, tankers were dedicated to a specific trade. This had several effects. Even though some surplus tanker capacity could occur at times when buyers were taking their contractual minimums, it was difficult to reschedule the surplus vessels since they were technically committed to the buyer's trade at his discretion. And the fact that newbuild tankers were commonly ordered to service a new LNG contract, left some existing tankers that had become surplus for one reason or another to remain in layup. A number of tankers originally ordered for the Algeria/US trades and the PacIndonesia project from Indonesia to the US West Coast in the 1970s remained in layup for fifteen years or more when those trades were abandoned.

One of the features of most contracts was the 'Destination restriction' clause. This limited the ability of the buyer to resell any surpluses that he might experience to his own account, thereby preserving any margin on the resale for the account of the seller. These clauses are discussed further in Chapter 4.

Notes

1. 'Importing Gas Into the U.K. – Gas Quality Issues; A Report to the Department of Trade and Industry, Ofgem and the Health and Safety Executive' by Ilex Energy Consulting, November 2003.

3. GAS INDUSTRY RESTRUCTURING – A CHALLENGE TO THE TRADITIONAL SYSTEM

The theoretical model for the restructuring of the gas – and electric power – industries represents a substantial challenge to this highly-structured, risk-averse form of business relationships. The restructuring process – first begun in the USA, Canada and the UK – is predicated on the assumption that the traditional form of government monopoly or regulated public utility operation of electricity and gas is inefficient and that a system that introduces market competition inherently provides lower prices and more desirable service options for consumers. It envisions free market competition among buyers and sellers to set commodity prices for gas – 'gas-to-gas competition'.

But since the supply of gas is usually geographically removed from its ultimate consumption, the model also envisions a competitive market for transportation capacity in a system that is subject to open – or third-party – access. For LNG, the model thus sees the 'LNG chain' reconstructed efficiently through independent competitive offerings of each of the relevant links which are free to operate independently of one another. And since many market decisions involve time lags between buyers' and sellers' revenue objectives with volatile price behaviour in the meantime, it also envisions a system of 'risk management' through the use of various types of financial derivatives – futures contracts, options and swaps.

The restructured industry in North America and the United Kingdom features a high proportion of spot trading, with prices that are often very volatile. The traditional long-term contract is all but extinct. Those contracts that remain are of comparatively short duration. Contract prices are keyed to a gas market indicator, since oil-linked pricing is a poor indicator of the value of gas in a gas-to-gas competitive market. And the fact that pricing is tied to the market makes the traditional take-or-pay contract of limited value.

Trade press reporting for a reference point such as Henry Hub in the USA or Bacton in the UK provides market information for traders. Less liquid quotations for other 'hubs' provide a means of developing 'basis differentials' for relating prices at other locations to the reference price. And while some abuses have developed over trade press price reporting, the futures market (such as the Henry Hub quotation on the New York Mercantile Exchange) provides transparent market information for risk management. Transportation capacity, like the commodity itself, can be readily traded among parties.

If there is one single feature that differentiates the restructured North American and European gas industries from the traditional terms of trade in LNG, it is the disappearance of the long-term contract as the central business relationship between buyer and seller. Therefore the central questions in determining how a global gas market is likely to develop are whether or not the traditional Sales and Purchase Agreement will survive in a restructured LNG industry and, if so, in what form.

4. TERM CONTRACTING – BALANCING INVESTMENT RISK WITH MARKET REWARD

The process of restructuring the gas industries in the USA and in the UK to make them more competitive focused on two essential elements. The first was regulatory intervention in existing contractual relationships between buyers and sellers, freeing sellers to shop for low cost gas among suppliers. In the USA this was accomplished by FERC Order 380 relieving buyers of their minimum bill obligations. In the UK, intervention was accomplished by forcing the monopoly supplier, British Gas, to divest itself of a portion of its customer load. The second element was the requirement that transportation systems be open to third-party access to enable producers and consumers to negotiate directly with one another without the monopoly control of a merchant transporter. The transportation infrastructure in both countries was relatively mature. That meant that the emphasis could be placed on efficient allocation of existing capacity, rather than on creating a favourable climate for investment in new infrastructure. It also helped that these efforts to deregulate took place during periods of gas surplus in both countries, making it easier to find suppliers who were prepared to compete for market outlet.

Where new infrastructure has been needed in these new, restructured markets, a limited form of long-term contracting – the 'ship-or-pay' agreement – is still commonly utilised. An 'open season' bidding process is used to allocate capacity on the proposed facility and the selected shippers undertake a long-term commitment to pay what amounts to the fixed charges on the investment, thus facilitating long-term financing of the project. The ship-or-pay agreement differs from the classic long-term contract in that it is for transportation only – not the commodity – and can be freely traded among potential shippers.

International gas industry restructuring is more complicated, since governments usually lack the jurisdiction to intervene directly in foreign contracts. This has made it more difficult to achieve a workably competitive market on the Continent than it was in the United Kingdom. The restructuring in Canada was a direct result of the US contract intervention by providing US buyers the excuse to walk away from uncompetitive Canadian contracts.

A limited amount of direct intervention to achieve restructuring is possible. LNG – once landed – enters a competitive market in those countries that have restructured their industries, and many of the more restrictive contract provisions cannot survive market competition. The principal focal point of receiving country regulation of LNG has been on the requirement for third-party access to receiving terminals. This has been a contentious issue, both in North America and Europe. Another problem has been the use of destination clauses that prevent the buyer from reselling volumes in a secondary market when conditions favour it. This has been a focus of major disputes between the EU and major suppliers, particularly Sonatrach and Gazprom. All suppliers including the Norwegians and Nigeria LNG have been required to renounce such clauses by the EU Competition Authorities and no supplier will be allowed new contracts without such an agreement.

But there are limitations on what such intervention can achieve – and indeed some question in the case of LNG if it is really constructive. The real future of the long-term LNG contract is most likely to be decided by the participants in the industry themselves, as they seek to balance the rewards of a more open and competitive market with the investment risks inherent in this capital-intensive business.

The more enthusiastic advocates of the fully-competitive market model see the growth of short-term trading in LNG as the wave of the future, and one that signals the demise of the traditional LNG contract. Certainly, the surplus of LNG offerings in the past several years has appeared to create a buyers' market in LNG, and short-term trading is on the rise. This suggests that it might be possible in the relatively near future for buyers to contemplate the possibility of relying totally on short-term or spot purchases – with reliance on financial derivatives for risk management – as the free market model would suggest.

There is little evidence, however, that sellers are ready for such a radical step. Both Mobil in Qatar and Shell in Oman in 1996 supposedly considered the option of justifying new LNG trains on the basis of large spot volumes, but rejected it as too risky.[1]

No country, no matter how aggressive in the short-term market has placed as much as 30% of its exports in any one year in short-term trading, and all expansions, like the financing of the earlier trains, have been based on underlying long-term contracts. Since no supplier has yet undertaken to build a new facility on a purely speculative basis without strong indications that it will have the contracts in hand for much of the volume, it would seem that the long-term contract is still alive and well.

However, it is clear that companies are willing to take greater speculative risks that they can convert active negotiations into contracts than they might have done in an earlier period. The Asia Pacific market has proved to be the most competitive and the initial decision to move forward on Sakhalin II appears to have been taken with only 58% heads of agreement coverage (29% coverage of the two train project) of the first train to Japanese customers. But these volumes seem almost certain to be converted into contracts and the volumes have since been increased. In addition, contract negotiations for sales to Korea and to the US West Coast are active. Thus while the decision to proceed is somewhat speculative, the project is seeking contract support rather than relying largely on uncommitted short-term sales.

Some indication of the persistence of long-term contracting in the justification of new LNG projects is provided by an analysis of reported volume commitments for new LNG projects. Some LNG market watchers maintain a schedule of potential new LNG projects classified by their likelihood of commercial implementation. Figure 4.1 shows one such classification broken down by exporting region as well as by Firm, Probable and Possible categories. A 'Remote' category is not included.

Figure 4.2 provides an analysis of the balance between third-party[2] commitments and uncommitted or self-contracted volumes for the Firm and Probable categories. Eighty-five percent of the volumes potentially scheduled to go on line between 2002 and 2010 have been committed to third parties on long-term contracts. Only 15% represent uncommitted volumes or those that the supplier has self-contracted with his own marketing affiliate.

But a continuation of long-term contracting does not imply that the earlier, rigid form of contracting is here to stay. There

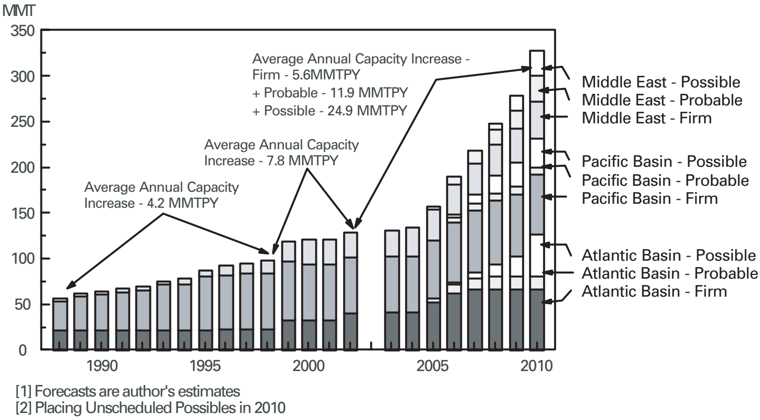


Figure 4.1: History and Forecast of Firm, Probable and Possible LNG Liquefaction Capacity by Region

Source: Author's estimates

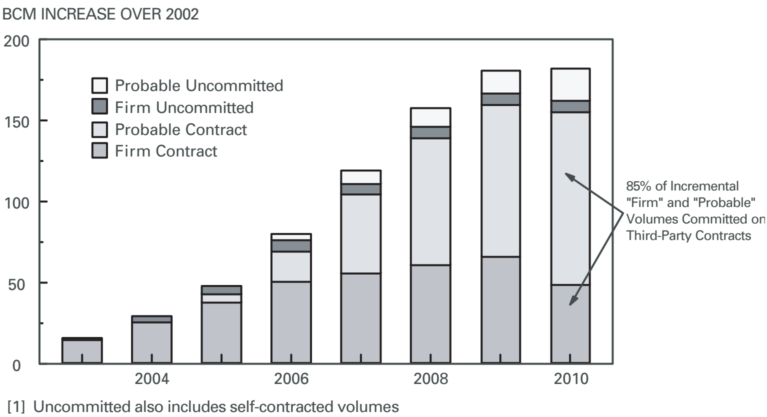


Figure 4.2: New Firm and Probable Contract Volumes

Source: Author's estimates

is substantial evidence that the more competitive patterns of recent trading have opened up new options to make contracting more flexible.

The emergence of a buyers' market in LNG has tended to mask an underlying erosion in the ability of buyers to make the kind of long-term contract commitments that were once the standard in the industry. The liberalisation of gas markets has largely eliminated the ability of government monopoly or regulated utility buyers to lay off the volume risk on their customers. Furthermore the emphasis on freer competition has exposed many buyers to interfuel-competitive price risks that were not envisioned earlier. And the financial community's concerns about the creditworthiness of some of the newer buyers, such as some Indian power plant purchasers, raises new questions about the riskiness of the traditional contract. Hence, even if long-term contracts remain as a major part of the new LNG market, their volume and pricing clauses are likely to undergo substantial change.

The classic combination of a take-or-pay agreement coupled with an oil-linked pricing clause has been under fire for some time, even before more liberalised markets began to appear. Buyers are increasingly demanding greater take flexibility and the classic oil linkage, which could once be defended as a measure of interfuel competition, is no longer representative of the market as gas now rarely finds oil as its chief competitor. Oil-linked pricing remains, but in many cases because the contracting parties do not appear to have come up with a better alternative.

LNG projects are capital-intensive and thus there are severe economic penalties to projects that fail to achieve high capacity utilisation rates. The take-or-pay clause, coupled with a price clause, in the traditional contract was the seller's guarantee of efficient facility utilisation, but it exposed the buyer to the possibility of economic loss if the pricing clause later forced him to take volumes that were less attractive than he had envisioned when he first signed the contract. Clearly, the more responsive the pricing term was to the buyer's actual market situation, the less would be the loss.

The experience in Japan, which has been the Pacific Basin market leader, illustrates the nature of the problem. Before the recent resurgence in interest in Atlantic Basin LNG, six Japanese utilities accounted for nearly 40% of world LNG trade.[3] Three of them – Tokyo Electric in Tokyo, Kansai Electric in Osaka and Chubu Electric in Nagoya – alone nearly accounted for 30 per cent. The Japanese contracts are linked to crude oil prices by reference to the Japanese Customs Clearing price for crude oil (JCC – often called the 'Japanese crude cocktail').

When the precedents for the oil-linkage were first established, Japanese power generation was heavily dependent on residual fuel oil firing. The decision to tie LNG take-or-pay contracts to a crude oil pricing standard, indirectly linked the dispatch of the LNG and oil-fired generating units since both fuels were similarly affected by changes in world crude prices. This linkage effectively precluded the kind of rapid utility switching from gas to oil that has recently characterised the US market.

But oil firing, which reached a level of 73% of generation in 1973, had fallen to 10% by 2001.[4] The growth of base load coal and nuclear generation has not only squeezed out most of the oil generation, but it has increasingly forced LNG to assume some of the peaking role once carried by oil. Hence the interest in more flexible contracts.

The advantage of gas-fired combined cycle generation to the LNG supplier is that it permits a higher market price as its lower capital cost and higher thermal efficiency can be traded off against the higher capital costs of alternative generation. But that advantage for LNG becomes a substantial disadvantage in dispatching generating units since it locks in a high short-run marginal generating cost for gas. Generally, electric units are dispatched (scheduled to run) based on their marginal generating costs. Therefore a coal-fired unit with low marginal costs, but high fully-allocated costs, might be scheduled to run preferentially as base load over a lower overall-cost gas-fired combined cycle unit. Thus at times when an economic downturn might lead to over-capacity in generation, electric dispatchers might be expected to idle the gas-fired units selectively, absent the take-or-pay volume limitation. Since the Japanese utilities had a monopoly franchise, the economic inefficiency of 'must run' status for LNG generation could be passed on to the customers. But as the Japanese electric industry itself liberalises along with other markets for gas, this pass through behaviour may be threatened.

The contract pricing problem is even more acute when the customer is a stand-alone independent power project (IPP) operating in a liberalised electricity economy. There a pricing formula that yields too high a price simply shuts the unit down as other units with lower marginal costs are preferentially dispatched. One of the great problems plaguing the Bolivia-to-Brazil pipeline has been the difficulty of financing new gas-fired IPP projects when they are at dispatch risk to hydroelectric power during high water periods.

While one solution to the dissatisfaction with oil-linked pricing clauses has been to utilise coal or some mix of energy prices, a more logical candidate in a restructured gas industry in gas-to-gas competition is a price tied to a gas market indicator. In the USA, the Henry Hub quotation is the obvious candidate for such a role. And as a forerunner to the possible spread of gas-linked pricing to Europe, a number of companies have recently signed a pipeline contract with Centrica in the UK that was to be linked to a gas market indicator.[5]

There are three disadvantages to the use of a gas market indicator relative to an oil indicator as a measure of changes in energy prices. Gas prices appear to be more volatile than oil prices, even after accounting for their relatively more seasonal behaviour. Second, the great geographic dispersion of market transactions together with gas's much higher transportation cost means that some geographic 'place differential' or 'basis differential' must be utilised to relate dispersed sales prices to the marker price. And finally, if the gas is delivered to the same physical market as the gas tracking price series, and if the market is sufficiently liquid that the transaction will not move the market, the effect is to eliminate most of the buyer's risk thereby transferring virtually all of the contract risk to the seller. (What volume risk does the buyer assume if he can always turn around and resell the cargo at the same market price used in the contract?)

In the more traditional contract negotiations, contract flexibility has also been a target of buyers and in a buyers' market they have had some success at changing contract terms. This has taken several forms. It may involve reduction in the take-or-pay minimums or the inclusion of optional cargoes at the buyer's discretion such as a Korean contract with RasGas.[6] Or it may involve eliminating destination clauses (that restrict the buyer's ability to resell volumes in excess of his requirements). This has been a major issue with the EU for European pipeline suppliers and has shown up in a Nigerian LNG contract.[7]

One possible pattern that might be seen with increasingly flexible contracting was evident in a 2003 new contract between Petronas in its new MLNG Tiga expansion and three Japanese gas companies. The contract is for 1.6 million tons over twenty years. However, only the first 680 thousand tons is a typical base load take-or-pay contract. A second tranche, 440 thousand tons, rolls over every year without any take obligation on the buyer's part. And the final tranche of 480 thousand tons is simply an option on unsold Tiga capacity at the buyers' option.[8]

The movement away from oil-linked price clauses in long-term contracts to short-term or spot market purchases or even term contracts with gas-linked pricing poses a substantial challenge to gas sellers. While one of the complaints of buyers about oil linkage is the volatility of oil prices, gas prices are, if anything, even more volatile.

For a time, the working assumption in the USA was that gas-to-gas competition had become decoupled from oil competition and thus variations in oil markets were no longer relevant to gas price formation. However, the gas price shock in the USA in the winter of 2000/01 reestablished oil-to-gas competition through the mechanism of residual fuel oil switching in utility and industrial boilers.[9] In fact, for a brief period during that winter gas prices appeared to be set at even higher levels by switching at the margin to distillate fuel oil. Thus, there appear to be three ranges of price relationships between gas and oil – a discounted gas-to-gas level where the prices of the two fuels are decoupled, a higher level where gas prices are linked to residual fuel oil, and a still-higher level where the gas price linkage is to distillate fuel oil.

These relationships are illustrated in Figures 4.3, 4.4 and 4.5. Figure 4.3 represents the classic supply/demand curve of basic economics. With increasing prices, demand declines and supply increases until a balance is struck at the 'market clearing price'. However, real gas markets are more complex than theory would suggest. Because of interfuel competition, primarily with oil in stationary applications, it is the gas price relationship to oil (gas price as a percent of the oil price), rather than the absolute price of gas, that tends to determine gas demand. This is illustrated in Figure 4.4. In surplus, all dual fuel loads have switched from oil to gas and the remaining market – load building – is quite

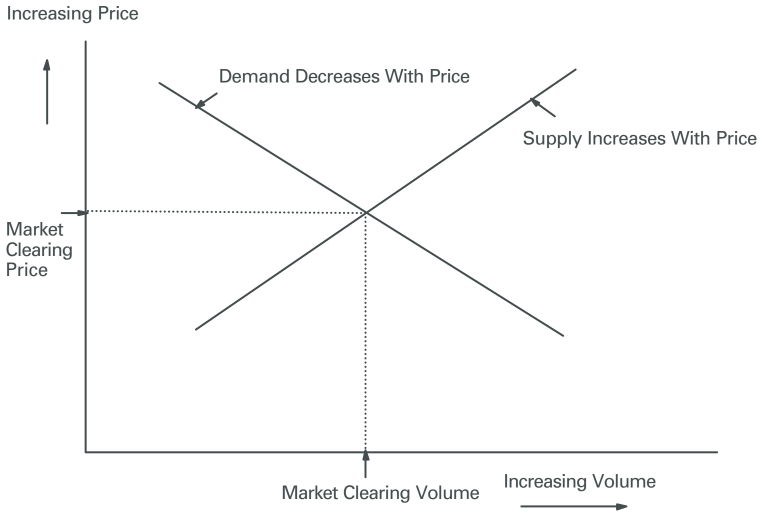


Figure 4.3: The Theoretical Behaviour of Supply, Demand and Price According to Economics 101

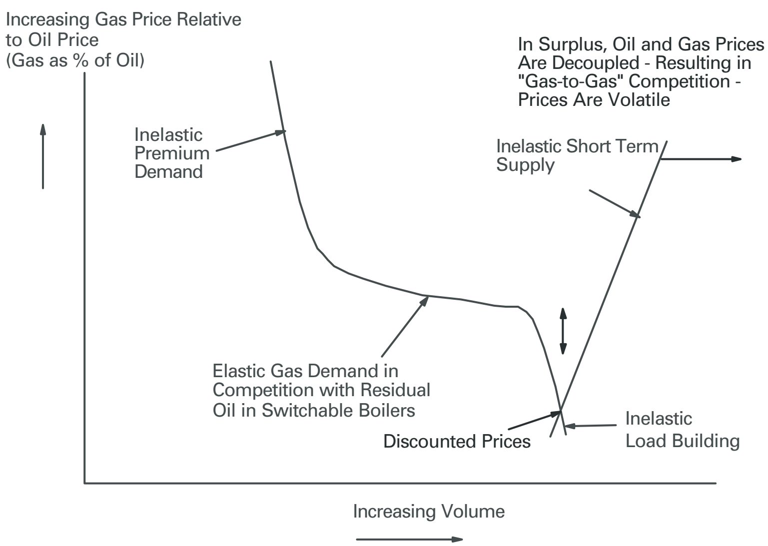


Figure 4.4: A More Realistic Short-Term Gas Supply/Demand Curve

inelastic. Gas prices become decoupled from oil and gas-to-gas competition is the result.

However, with tightening gas supply, prices rise until switching to residual fuel oil begins and stabilises the gas-oil price relationship as long as a significant number of customers remain able to switch between gas and residual. In the USA this relationship has tended to occur at a gas price of about 90% of oil prices on a heat content basis ($3.88/MMBtu gas on a $25/bbl oil price).

The experience in the USA, first observed in the winter of 2000/2001 and occurring frequently since that time, is that the residual fuel oil switching bench is soon exhausted and interfuel competition moves into the much higher distillate price range. This is illustrated in Figure 4.5. If North American gas prices can fluctuate among the three oil-to-gas price relationships, it argues that the US gas market indicator ought to be more volatile than oil prices alone.

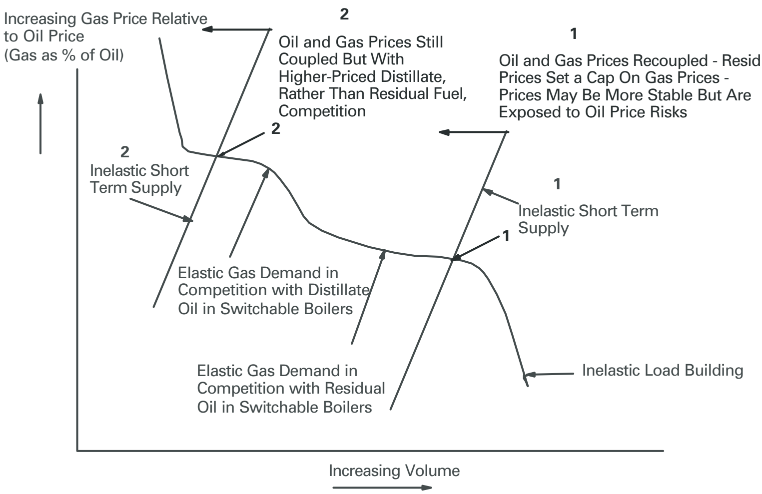


Figure 4.5: Another Short-Term Gas Supply/Demand Curve

The existence of a world oil market is largely predicated on the low costs of tanker transportation coupled with the role of the Gulf as a supplier of last resort. Therefore the issue of oil 'place' or 'basis' differentials has usually not been a significant issue in oil price escalators. However, the much higher costs of gas transportation can cause substantially differing prices at different geographic locations. In the USA these basis differentials from the Henry Hub market are regularly monitored by trade press pricing services and market trading activity is often based on estimates of their future behaviour. Figure 4.6 is a map illustrating basis differential relationships.

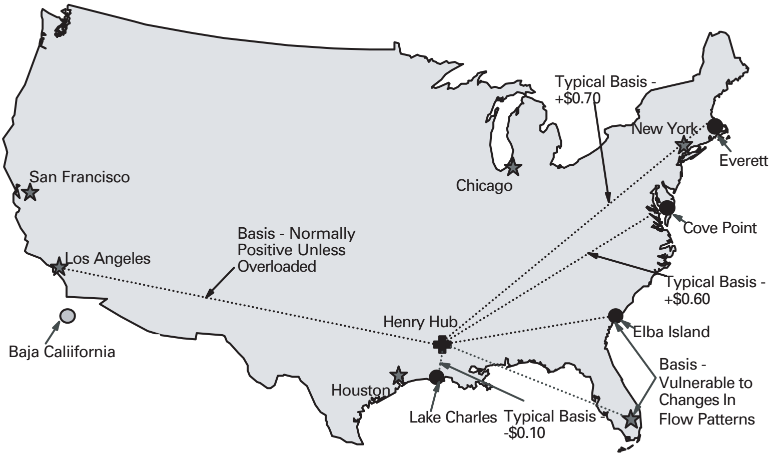


Figure 4.6: The U.S. Basis Differential System – Premiums over Henry Hub Based on Transportation Costs to Market

Source: Author's estimates

The fact that basis differentials for markets removed from the pricing reference point can themselves vary quite widely introduces a further element of 'basis risk' into the pricing equation. For the US market, for example, an LNG delivery to the Everett, MA or Cove Point, MD terminals would be expected to enjoy a higher price than a delivery to Lake Charles, LA near the Henry Hub pricing point because of the basis differentials to Northeastern markets. Similarly, proposals to deliver LNG to California (or to Baja California in Mexico for reshipment to the United States) might normally expect a positive basis differential over Henry Hub.

However, the fact that local markets can easily be overloaded, sharply affecting the historic differential, introduces a new element of risk into the transaction. This phenomenon was illustrated in 1994/1996 when a pipeline expansion by Pacific Gas Transmission into the California market caused a collapse of the normally positive basis differential over Henry Hub so that for a period California border prices were lower than those in Louisiana.

The closer the transaction is to the market reference location, the less the degree of basis risk in the transaction. An LNG delivery into Lake Charles might be expected to have little or no basis risk to Henry Hub. However, such a delivery, if made on a contract that was keyed to Henry Hub as a gas market indicator, would involve little volume risk to the buyer since he could quickly resell the volume in the highly liquid Louisiana market.

The effect of many of these new pricing and volume changes is to shift the market risk towards the seller. Thus the way in which sellers ultimately adapt to this new risk profile will have much to do with the future shape of the industry.

The liberalisation of the gas industry has created a whole new class of buyers – the marketing companies. These companies may be affiliates of either buyers or sellers – and thus their fundamental corporate trading interest arguably remains that of the parent – but the new system has spawned a new group of traders without the underlying upstream or downstream assets of the traditional market participants. Companies such as Enron, Dynegy and Williams were prepared to take title to the gas and market it independently. Some of this group undertook ship-or-pay agreements on the new pipelines and for a time it appeared as if this new class of potential buyers would be prepared to become major customers for LNG contracts, adding liquidity to the market. But the bankruptcy of Enron and the subsequent financial problems of the marketing companies as a group have raised questions about the creditworthiness of companies that are not backed by solid physical assets and suggests that they may not be the players in LNG that they once were expected to be. The major companies now seem poised to undertake much of the investment role that the merchants were once expected to assume.

Notes

1. *World Gas Intelligence*, 26 January 1996, p.3.

2. In this text, 'third-party' commitments refers to sales to independent purchasers as distinct from 'second-party' commitments, which are downstream sales to one's own marketing organisation.
3. Jensen estimates based on corporate annual report data.
4. The 2002 and 2003 Japanese oil consumption was distorted by the shutdown of Tokyo Electric's nuclear plants.
5. *Petroleum Intelligence Weekly*, 17 June 2002, p.7.
6. *World Gas Intelligence*, 23 October 2002, p.1.
7. *European Gas Markets*, December 2002, p.7.
8. *Petroleum Intelligence Weekly*, 29 April 2002.
9. Jensen, J., 'The Outlook for U.S. Natural Gas Supply and Demand and the Potential Role for Liquefied Natural Gas', A Presentation to the NAPIA/PIRA Joint Annual Conference, La Quinta, CA October 10, 2002 (unpublished).

5. THE EVOLUTION OF SHORT-TERM LNG MARKETS

While a very small short-term LNG market has been in existence for nearly a decade, it has grown rapidly in the past several years. As recently as 1997, short-term LNG transactions accounted for only 1.5% of international LNG trade. In the ensuing five years, the volume of short-term transactions increased sevenfold and in 2003 accounted for 8.9% of international trade (See Figure 5.1). As previously mentioned, many of these transactions, particularly in the Pacific Basin are better described as 'short-term' sales rather than genuine 'spot' sales.

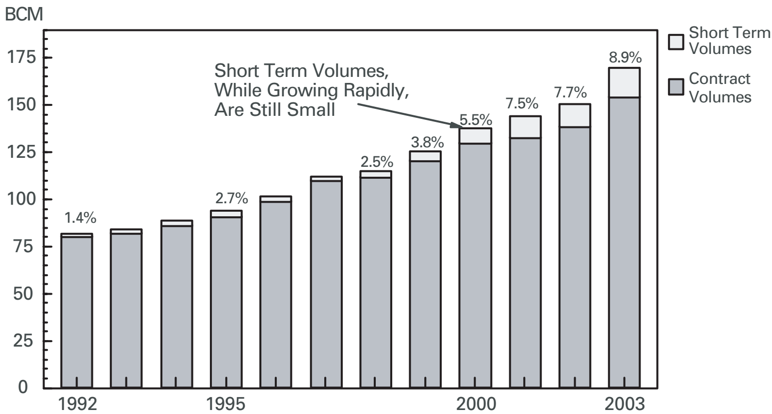


Figure 5.1: LNG Trade Showing the Growing Role of Short-term Sales

Source: Cedigaz

Substantial surpluses of LNG capacity relative to demand existed throughout the 1980s, largely as a result of pricing disputes between Algeria and its customers. But the early inflexibility of trade linkages made it difficult to consider any significant short-term trading. However, by the early 1990s, surplus capacity again began to appear and serious short-term market began to develop. Figure 5.2 compares LNG liquefaction capacity with actual trade.

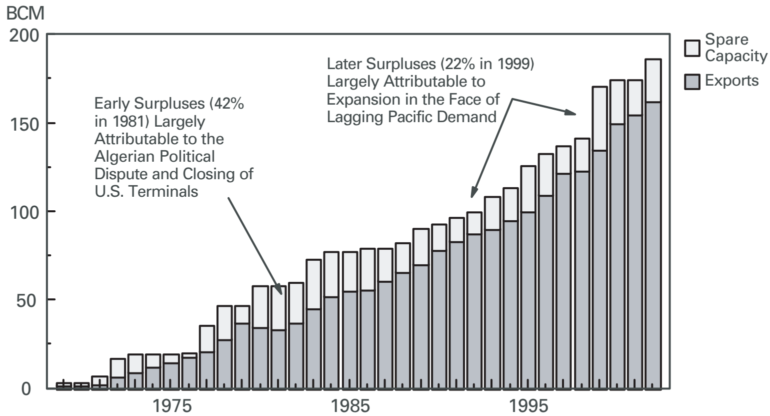


Figure 5.2: LNG Exports Compared With Liquefaction Capacity

Source: Author's estimates based on Cedigaz data

5.1 Sources of Short-term Volumes

The early appearance of capacity surpluses east of Suez in the early 1990s seemed to be more by accident than by design. It was the result of over 8 million tons of de-bottlenecking capacity additions in Southeast Asia during a period when both Indonesia and Malaysia were adding expansion trains. It was sustained later in the decade by the slowdown in Asian markets and by the emergence of new export capacity from Qatar and Oman in the Gulf. But by 1999, further Middle East expansions (as well as the startup of Trinidad and Nigeria in the Atlantic Basin) institutionalised the surpluses and by now some of the excess capacity appears to have been created deliberately to enable companies to participate in spot and short-term trading opportunities.

The Pacific Basin provided much of the earlier short-term volume, but the active trading market that has developed in the Atlantic Basin has provided an opportunity for Atlantic and Middle East sources to grow rapidly (See Figure 5.3). The destinations for this trading activity have been remarkably concentrated. Since 1996, four countries – the USA, Spain, Japan and Korea – have accounted for more than 80% of the short-term volumes (See Figure 5.4).

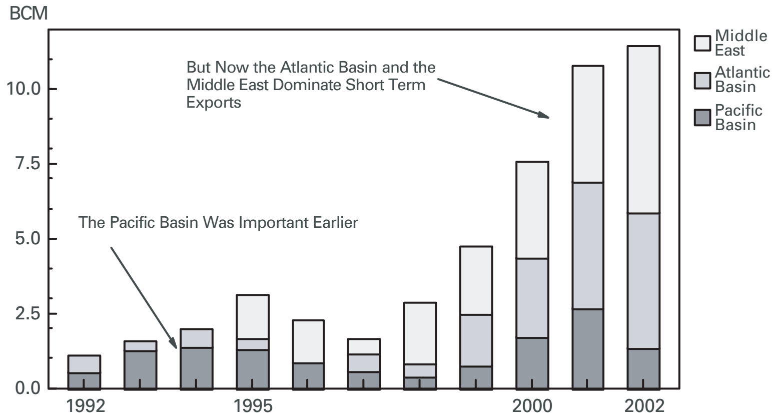


Figure 5.3: Source of Short-term Exports by Region

Source: Author's estimates based on Cedigaz data

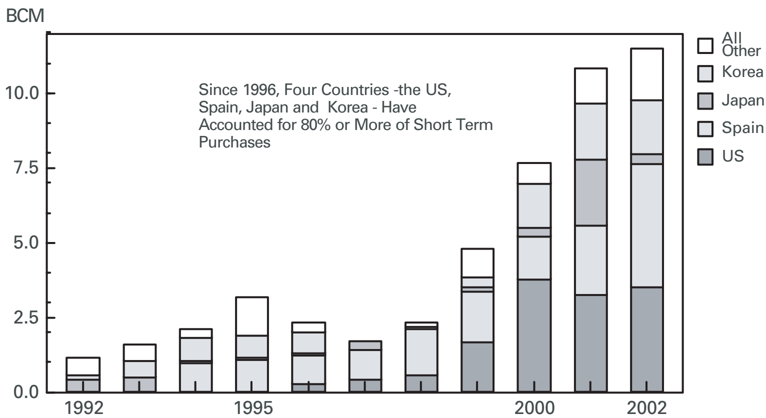


Figure 5.4: Destination of Short-term Imports by Country

Source: Author's estimates based on Cedigaz data

As the rigidities associated with the old style contract have softened, more volumes have become available for short-term and spot sales. The flexible volumes originate in several ways. Much of them come from the mismatch between customer market growth and the early availability of full capacity to cover the plateau period of the contract. Most long-term contracts have a 'ramp-up' period to allow the customer to grow into his contract commitments, and these volumes are increasingly being utilised to feed the short-term market.

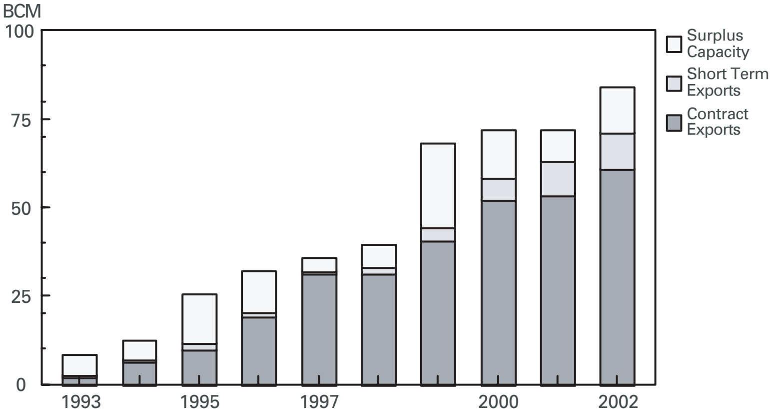
In addition, as the industry ages, more and more gas is coming to the end of the original contract period, enabling the sellers to renew the original agreement or to take back the volumes for more flexible sales. De-bottlenecking of existing facilities creates capacity that has already been financed by the original contract. With increased competition among projects for the market, companies seem more willing to commit to a project with some portion of the output 'uncovered'. And since the seller's greatest concern is debt service while the loan obligation is still outstanding, it may increasingly be possible to tailor the contract length to the shorter period of loan payout, giving the seller greater flexibility to put volumes on the short-term market.

'Ramp-up' volumes have existed for many years but their availability for short-term transactions is more recent. Because they become available when projects start up, they can be quickly put on the market without waiting for complex negotiations between buyer and seller. Actual ramp-up capacity potentially available for short-term markets is comparatively large relative to their actual utilisation for short-term market sales. This is illustrated in Figure 5.5, which shows the incremental growth of capacity, contract exports and short-term sales since 1992.

The Middle East, with its geographic position as a 'swing supplier' between Asia and the Atlantic Basin, has been particularly active in placing ramp-up volumes on the short-term market (see Figure 5.6). While Algeria, in the Atlantic Basin, was not an early participant in short-term trading, the newer entrants – Trinidad and Nigeria – have been active suppliers to the market (Figure 5.7).

The Pacific suppliers (Figure 5.8), farther away from markets in the Atlantic and growing somewhat less rapidly, have been slower to place ramp-up volumes on the market. The Pacific trade has been also been complicated by the gas supply and political troubles with Indonesia's Arun facility.

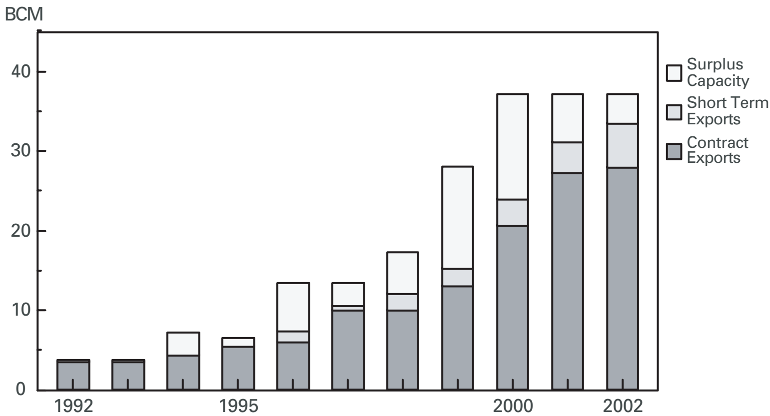
In a business that began its early period of growth in the 1970s with contracts of twenty years or more, it is not surprising that many of the early contracts have reached the end of their



Note: Capacity Figures Are as of the End of Year and Thus May Overstate Annual Surplus in an Expansion Year

Figure 5.5: Cumulative Incremental Growth of Capacity and Trade for the World

Source: Author's estimates based on Cedigaz data



Note: Capacity Figures Are as of the End of Year and Thus May Overstate Annual Surplus in an Expansion Year

Figure 5.6: Growth of Capacity and Trade for the Middle East

Source: Author's estimates based on Cedigaz data

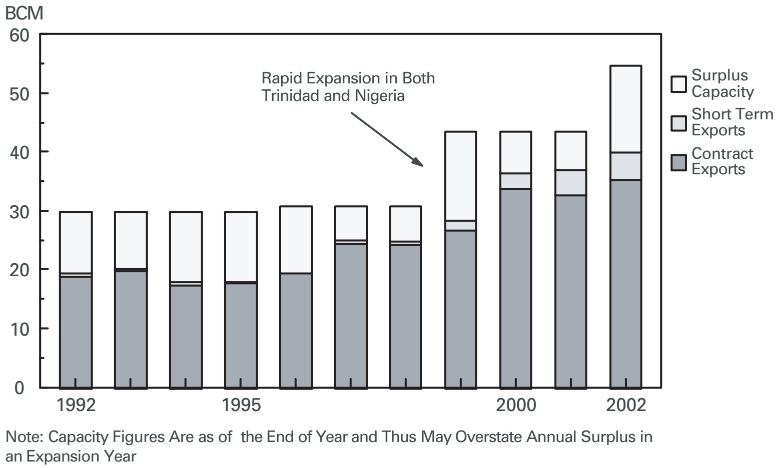


Figure 5.7: Growth of Capacity and Trade for the Atlantic Basin

Source: Author's estimates based on Cedigaz data

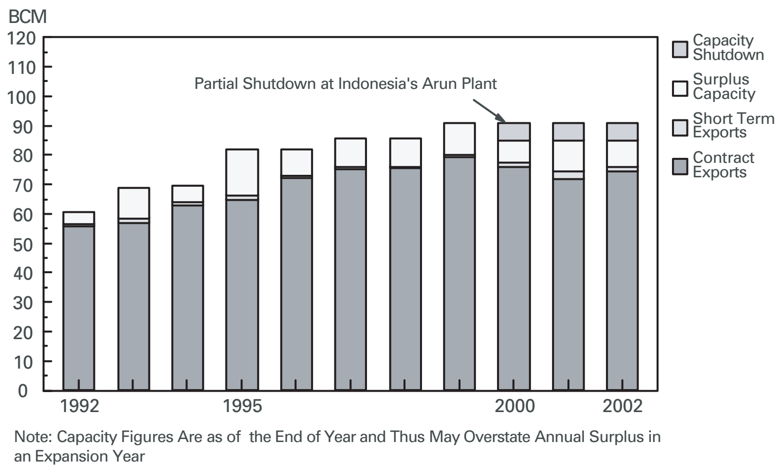


Figure 5.8: Growth of Capacity and Trade for the Pacific Basin

Source: Author's estimates based on Cedigaz data original period and have been subject to renegotiation. In most cases, these contracts have been renewed, sometimes with revised contract terms, but usually with the original buyer.

With the growing interest in short-term trading and with buyer interest in more flexible contracts, it is less likely that those contracts coming up for renewal will simply be rolled over to their original buyer. Some may well be taken back by the sellers to place on the short-term market. However, it is likely that many of the buyer/seller linkages will be retained, albeit with altered contract terms.

The rate at which contract expiration makes volumes under existing contracts available for reselling is inherently slow, given the long-term nature of most of the early contracts. Recent contracts frequently have shorter terms, but it will take time for these newer contracts to expire. New contracts may be of fifteen years duration, although some extensions or de-bottlenecking expansions may have even shorter terms. Figure 5.9 shows the rate at which contract expiration is scheduled to take place. Expiration rates are fairly modest until the end of the decade when some major existing contracts are up for renewal or abandonment.

Between 2009 and 2011, about 23 million tons of contracted

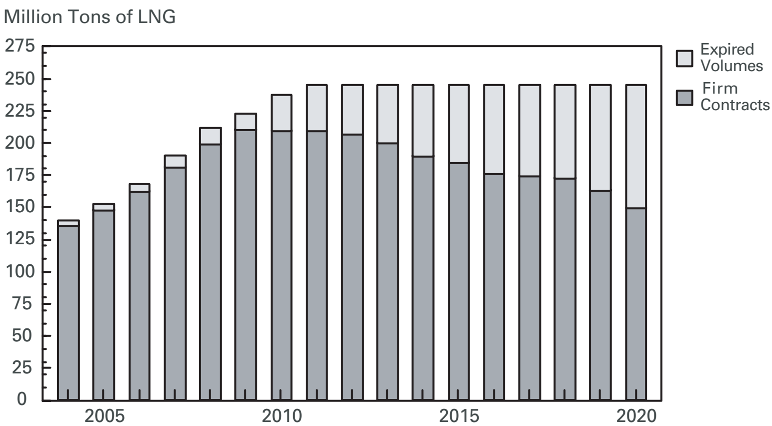


Figure 5.9: Schedule of Worldwide Contract Expiration Volumes

Source: Author's estimates

volume are scheduled to expire, 76% of which will be in Indonesia and Australia. The rapid falloff in contract commitments in the Pacific Basin is shown in Figure 5.10. In Indonesia's case, the declining fortunes of the Arun plant in Western Sumatra complicate the wind-down process. Arun's gas supply is in an advanced state of depletion and the separatist rebellion in the Aceh province is a disincentive to salvage its operation through bringing in gas from elsewhere. Nonetheless, Indonesia is still attempting to offset the loss by expansion at other locations, particularly from the newer proposed Tangguh project.

The contract expiration process will be somewhat slower in the Atlantic Basin and in the Middle East, whose contract schedules are shown in Figures 5.11 and 5.12. Because their projects started earlier, the Atlantic Basin contract expirations are concentrated in Algeria. Because Qatar and Oman contracts are recent and the Abu Dhabi contracts have been renegotiated, contract expiration is not a factor in the Middle East.

The slow pace at which contracts are up for renewal does not necessarily preclude early renegotiation. The combination of sellers seeking expanded markets and buyers wanting more flexible contracting terms gives significant mutual incentives to reopen some of these contracts before they reach maturity. However, it

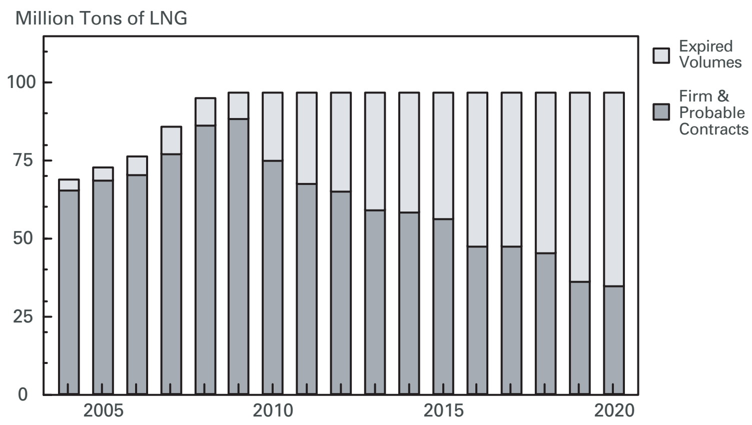


Figure 5.10: Schedule of Pacific Basin Contract Expiration Volumes

Source: Author's estimates

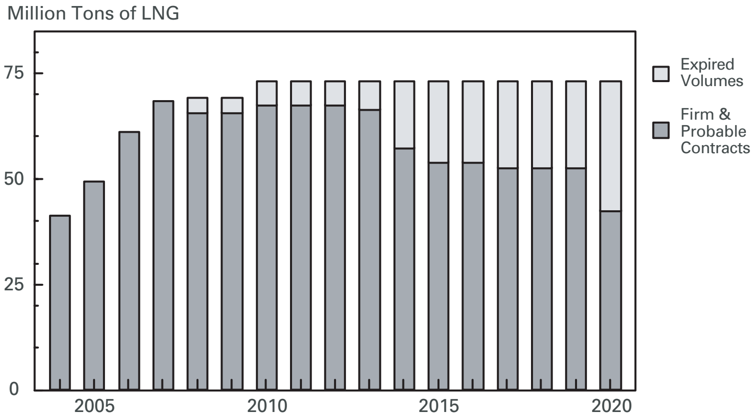


Figure 5.11: Schedule of Atlantic Basin Contract Expiration Volumes

Source: Author's estimates

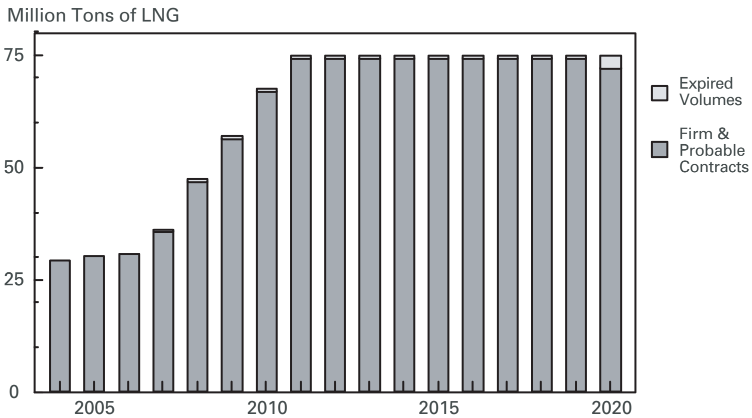


Figure 5.12: Schedule of Middle East Contract Expiration Volumes

Source: Author's estimates

is probably more likely that these early renegotiations will lead to higher – if more flexible – contract volumes than they will to release contract volumes to the spot market.

Another source of flexible volumes is the increase in capacity through de-bottlenecking. Figure 5.13 compares the growth in new and de-bottlenecked capacity since 1990. De-bottlenecking effectively added about one-sixth of the incremental volume since that time.

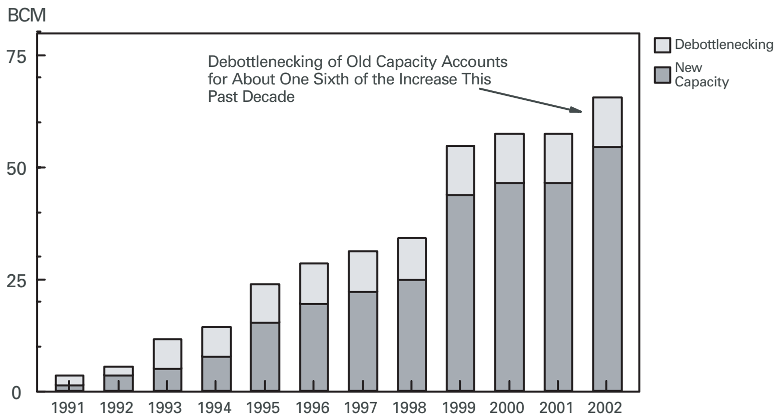


Figure 5.13: Cumulative Growth of New and De-bottlenecked Capacity

Source: Author's estimates

Since the original contracts effectively financed the plant, the de-bottlenecked capacity is nearly costless to the sellers. While this capacity could readily be diverted to the seller's portfolio of short-term volumes for trading, much of the de-bottlenecking – particularly in the Pacific Basin – was also contracted out on a long-term basis, often as a part of a renegotiation of the original contract.

The slowdown in the Pacific market has intensified the competition among a number of potential projects. This has in turn been exacerbated by the trend to larger train sizes. A combination of earlier growth with smaller trains meant that project developers could justify expansions more easily. But now it takes longer to assemble enough demand to justify one of the new, larger trains. This is illustrated in Figure 5.14, which shows the trends, both in annual Pacific demand growth and in train sizes. Until recently, the average annual increase in demand was more than enough to justify one new typical train. That is no longer true as average demand growth has now fallen behind average train sizing.

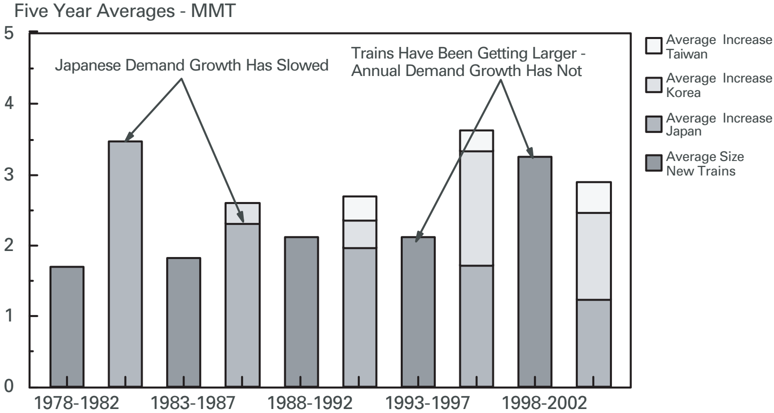


Figure 5.14: The Average Annual Growth in Asia Pacific Demand Compared to Average New Train Sizes

Source: Author's estimates based on Cedigaz data

The consequence of these trends is that competing projects often find it difficult to justify expansion using the old contract coverage of an earlier period. Faced with competition from other projects in the same situation, project developers have shown more of a tendency to launch a new project with contract coverage that might have been deemed imprudent ten years ago. Hence, more volumes in new projects show up as 'uncommitted', that is uncovered by long-term contracts.

5.2 The Effect of Tanker Capacity on Short-term Markets

In traditional LNG contracting, tankers were dedicated to specific trades. The contractual obligation to deliver the maximum contract quantity at the buyer's discretion usually meant that the tanker was unavailable for other cargoes even when the buyer was taking his minimum. Tanker maintenance was commonly scheduled for those periods when the buyer's demand was likely to be low, but still some degree of tanker idling was inevitable.

The common practice of requiring newbuild tankers for new contracts led to a relatively inflexible tanker fleet. If a tanker were to be idled for any reason, it was very difficult to find another charter for it and it was likely to be laid up. In the late 1970s and early 1980s, several trades for which tankers had been ordered either failed to materialise or collapsed after a brief period of operation. These included the failed PacIndonesia trade from Indonesia to California and the Algeria/US trades to Cove Point, Elba Island and Lake Charles, which shut down after less than two years. In addition, two tankers that had been built on speculation never got contracts. All in all, fifteen tankers were laid up by these events. Although six of these were subsequently scrapped, the remaining nine remained idle – several for more than twenty years – before being refitted for a newer, more flexible tanker market.

The contract inflexibility also tended to prevent the scheduling of tankers to cover cross shipping. This can occur when the tankers dedicated to one trade effectively cross in opposite directions, where an exchange agreement might minimise transportation costs. To illustrate, ConocoPhillips was considering at one point the possibility of bringing its Bayu Undan gas in the Timor Sea (via a Darwin, Australia liquefaction plant) into a possible Baja California terminal. It also is an owner of the Cook Inlet, Alaska LNG plant that is dedicated to the Japanese market. Had this venture gone ahead under the old dedicated tanker ground rules, the combined cross trade of Alaska/Japan and Bayu Undan/Mexico would have had a combined shipping distance of 10,547 nautical miles – Alaska to Japan of 3,250 nautical miles and 7,287 from Darwin to Baja. However had it been possible to make a flexible exchange deal of Alaska to Baja and Darwin to Japan, the combined shipping distance would have been more than halved – 2,191 for Alaska/Baja and 2,864 for the Darwin shipment or 5,055 nautical miles total. Cross shipping has not been a major issue to date, but with the growing geographic dispersion of supply sources and markets, it is likely to be more important in the future.

The early industry view was that LNG tankers had a limited effective life. Therefore, it was often assumed that a tanker would not outlast the terms of the original contract, and new vessels would need to be ordered if the contract was renewed. This early view has now given way to the recognition that these tankers may have a useful life of as much as forty years, and need not be replaced when a contract extension has been negotiated.

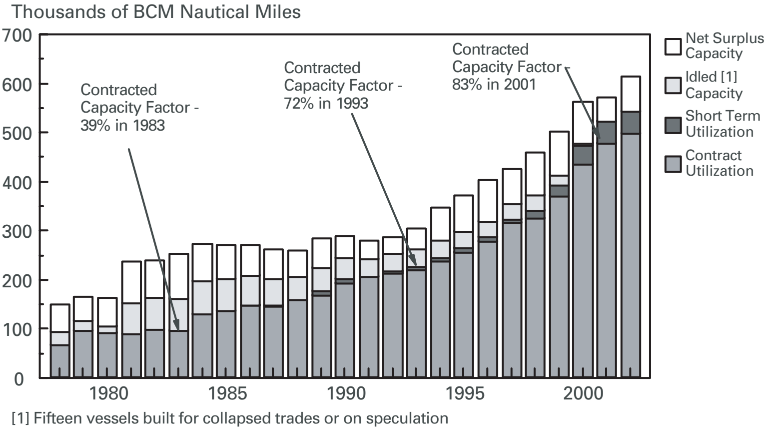


Figure 5.15: LNG Tanker Capacity Compared with Tanker Demand

Source: Author's estimates based on data from DVD Nedship Bank plc

The tanker inflexibility began to give way in the early 1990s. One of the first changes was the renewal of the Alaska/Japan contract in 1994. The contract renewal coincided with a de-bottlenecking of the plant and a decision to use somewhat larger newbuilds for the renewed contract. This idled the two original tankers, which were then purchased by BG and placed in other service. With the changing perception about useful tanker life, a new class of 'secondhand' tankers began to appear in the market. This pattern accelerated with the replacement of five Gotaas Larsen ships[1] that were chartered to the original Abu Dhabi/Japan contract when an expanded trade was initiated in 1995/1997.

Figure 5.15 provides a history of tanker capacity (in thousands of BCM nautical miles) compared with contract transportation utilisation. It also shows the BCM nautical miles of short-term volumes. The surplus capacity also isolates the laid-up capacity for the fifteen tankers that were laid up as a result of failed trades and speculative building.

Another landmark change in the tanker capacity relationship occurred in the middle 1980s, when the Bonny, Nigeria project was being developed. Shell had already acquired two of the laid-up tankers (the speculative ships) and placed them in service in 1990 for Asia Pacific service. The initial Nigerian feasibility studies of shipping LNG to Italy and to the USA failed to demonstrate economic feasibility, and the sponsors – Shell, Agip, Elf and NNPC – took options on seven of the remaining laid-up tankers. These so reduced the costs of transportation that the project became feasible. All seven are now in operation – six in Nigerian trade and one in Trinidad/Everett trade.

Figure 5.15 suggests that there remains an overhang of surplus capacity available to support extensive short-term market trading. However, it is not clear at what level of capacity utilisation the market becomes 'tight'. Press reports[2] during late 2002 spoke of 'tight' tanker markets as a result of upsets in the Asia Pacific market. But the average capacity factor for contracted volumes for the year was only 81 per cent.

Clearly some unutilised capacity is difficult to avoid. A tanker temporarily idled in one trade may not be able to take the time off its base contract to haul a cargo between a totally different source and destination. And in many cases the utilisation of the tanker is at the buyer's discretion. If he sees little to gain by diverting a tanker that would otherwise provide added security to his supply, he may not be willing to release the vessel temporarily.

One new trend in flexible contracting is to eliminate or curtail the destination restriction terms, thereby giving the buyer the possibility of economic gain if he diverts his own surplus into the short-term market. It remains to be seen how this trend in LNG contracting will affect the practical limit on tanker capacity factors.

It is apparent that the availability of surplus tanker capacity – and surplus liquefaction capacity – makes it possible to move LNG economically over much longer distances than are feasible for long-term contract operation. Figure 5.16 compares the effective average haul in nautical miles of contract and spot volumes.

There is some evidence that tanker investors are willing to speculate in new tanker capacity to trade on the short-term market. One press report[3] in 2002 estimated that 10% of the new tanker orders are speculative. While, presumably, some of the secondhand tankers – where the economic exposure of such an investment is limited – are obvious candidates, the conclusion is more ambiguous when it is applied to newbuilds. Some of the

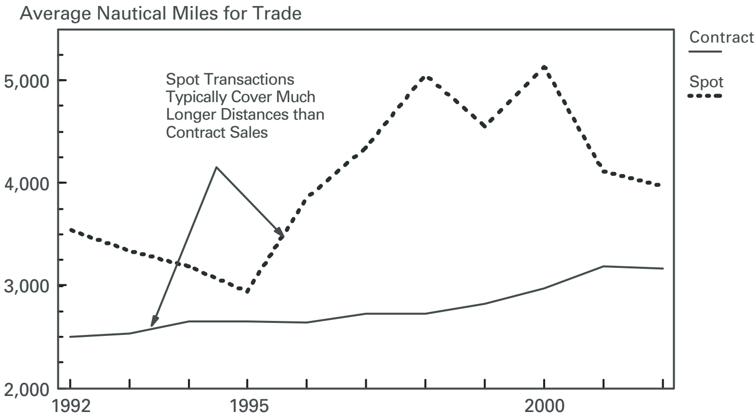


Figure 5.16: Comparison of Average Transportation Distance for Contract and Spot Volumes of LNG

Source: Author's estimates

merchants, such as Enron and El Paso, placed orders for speculative vessels before the financial troubles in that sector developed. Some of those orders have now been cancelled. The larger LNG majors, such as BG, BP and Shell, have all been mentioned as ordering uncommitted tankers. However, the growing trend by some of the majors towards downstream integration through self-contracting with their own marketing affiliates clouds the distinction between tanker contracting and tanker trading. A tanker that has been ordered to shuttle between various major company controlled liquefaction and receipt facilities may not appear to fit the traditional definition of a 'dedicated' trade, but it would be hard to class it as truly 'speculative'.

Notes

1. *World Gas Intelligence*, 25 November 1994, p.8.
2. *World Gas Intelligence*, 13 November 2002, p.6.
3. *World Gas Intelligence*, 18 September 2002, p.2.

6. THE EMERGENCE OF A NEW MARKET STRUCTURE

6.1 The Migration of Risk Upstream and Its Implications

The clash between the two structural models of the international LNG industry – the traditional, risk-averse, contract-dependent model and the free market, trading model – has substantially shifted the balance of risks and rewards among the parties in ways that are not yet fully understood. The long-term contract gave sellers the assurance that they had secure outlets without the need to integrate downstream as the industry has traditionally done in oil. However, it appears that it is increasingly difficult to find buyers in restructured markets, such as those in the United States and United Kingdom, who can deliver on the traditional volume commitment (an obligation tied to a gas market indicator is substantially weakened since it is so easy to lay off in the market; and the captive ratepayers are largely gone). Hence, a significant part of the market risk appears to have migrated upstream, and political risk has always been an issue in LNG. While the growing diversity of supply sources tends to insulate buyers from these political risks, sellers with investments in affected countries can best spread these risks by investing in a portfolio of supply sources.

6.2 The Potential for Financial Derivatives to Moderate Risk

Before the gas trading companies got into their financial difficulties, many were promoting an ambitious concept of using financial derivatives for long-term as well as short-term risk management. Taken to its extreme, the seller no longer had to rely on long-term contracts for his future cash flow but could utilise the longer-term derivatives market in order to lock in prices and manage risk.

In the USA the NYMEX futures market has proved to be highly successful and serves as a potential model for gas risk management in other countries. It has provided a very liquid vehicle for hedging short-term US gas market transactions. It has enabled companies to stabilise revenues and profitability when market volatility would otherwise cause them to fluctuate unacceptably. And it has enabled buyers and sellers to lock in current market pricing conditions for physical transactions that will not take place until some time in the future. Applied to LNG, it would enable the parties to offset the sometimes irregular delivery of LNG cargoes. And a transaction for Middle East LNG for the US East Coast can be locked in to the current market price despite the fact that it might take three weeks for the vessel to deliver the cargo.

Futures quotations on the NYMEX exchange are available for 72 months into the future, and for longer-term risk management, the over-the-counter swaps market extends the hedging period years into the future. While the NYMEX transactions are fully transparent, the swaps market lacks the transparency of the NYMEX exchange quotations.

The liquidity of the NYMEX market drops off significantly for later transactions, making it increasingly difficult to move large volumes without affecting the market. To pick a day at random, the report on NYMEX activity for 18 December 2003 showed an open interest of 48,125 contracts for January, the near month. For the July contract the open interest had fallen to 12,917 and for January 2005 it was down to 10,151. The December 2005 contract showed an open interest of only 4,160. There are no published figures for swaps activity, but its liquidity is also very poor for longer-term transactions.

At one point some vocal advocates of the use of financial derivatives argued that they could be ultimately used to hedge multi-billion dollar LNG investments, thereby replacing the long-term contract in managing project risk. The concept, highly controversial at the time, has now lost most of its credibility.

All financial derivatives depend on counter parties to offset the positions of those who want to hedge prices. For example, if a gas seller uses a futures contract to hedge against a price decline, someone in the market must be prepared to take a matching contrary position to balance the transaction. For near months, market speculators contribute significantly to that role, but as contracts lengthen speculative activity tends to decline. For longer-term positions, the market has relied more and more on the specialist market trading companies and the investment banks as the counter parties. Enron, for example, was a major specialist in long-term gas swaps. One of the principal consequences of its bankruptcy proceeding has been to default on some of its longer-term commitments, adversely affecting the profitability of those who relied on it for hedges.

The near collapse of the trading companies has markedly changed the outlook for long-term risk management in LNG. Since some of the affected companies were leaders in the effort to develop the long-term derivatives market, their problems – and in some cases complete withdrawal from trading activities – have sharply reduced the number of players who are prepared to accept that risk. If the idea that a financial derivatives contract could be used to hedge multi-billion dollar LNG investments was questionable before, it is now almost completely discredited. Who wants to buy a long-term insurance policy if the insurer may go bankrupt before the policy has a chance to pay off?

6.3 The Pressures for Integration Both Downstream and Upstream

In the face of these market and political risks, integrating downstream and creating a diversified supply portfolio would seem to make good sense as an investment strategy for producers. The problem is that the price tag for the highest degree of diversity is so large that few companies can afford it.

Figure 6.1 illustrates a 'greenfield entry fee' for what might be described as a fully diversified LNG portfolio involving supplies in the Pacific Basin, Middle East and Atlantic Basin and matching terminal capacity in Asia, Europe and North America. The $15 billion price tag is compared to the 2002 capital expenditures of the five super majors – the 'five sisters' – together with the smaller ConocoPhillips (BG is also a major player but, as a gas company, difficult to compare with the upstream oil producers).

Figure 6.1 assumes that 25% of total upstream capital budgets are available for LNG (taking 60% of the budget for the world outside North America and Europe and 40% of that is targeted on gas). It is apparent that the 'entry fee' remains large compared to available investment dollars for these very large companies.

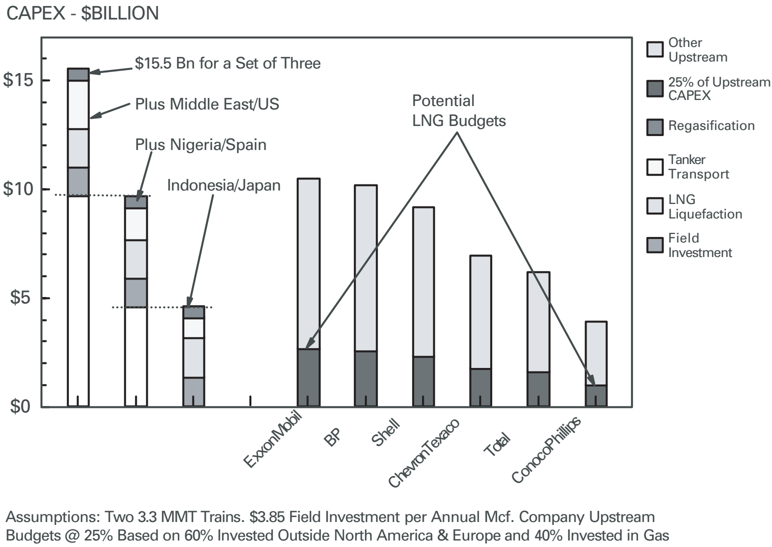


Figure 6.1: A Regionally Diversified Portfolio of Greenfield LNG Projects Compared to the Upstream Capital Budgets of Selected Companies

Source: Author's estimates based on Company Annual Reports

One new feature of the 'uncommitted' contract market is the emergence of self-contracting. Some of the larger LNG suppliers that are also large gas marketers, such as Shell or BG, have contracted some volumes with their own marketing organisations, thus effectively integrating downstream.

Integration in LNG has another face, as well. For those buyers who still exert some control over their own markets, the possibility of acquiring an upstream position in production – usually expected to be the most profitable link in the chain – offers a method of upstream integration. Kogas in Korea was one of the first buyers to acquire an upstream stake by obtaining an interest in Qatar's Rasgas 1 project. It has also been the path of the Chinese Offshore Oil Company (CNOOC) in acquiring an equity interest in the Australian North West Shelf project as a part of the Guangdong purchase contract and negotiating a similar position in BP's Indonesian Tangguh project in return for the Fujian contract.

It has also been the route that Tokyo Electric and Tokyo Gas have followed in acquiring an equity interest in the Bayu Undan project in the Timor Sea. Interestingly enough, ConocoPhillips – the seller in Bayu Undan – has reversed its role by acquiring a position in Qatar's North Field in return for a contract to buy from Qatargas for the US market. In that case, ConocoPhillips is offering access to the US market through its established marketing affiliate in the USA.

7. HOW LNG TRANSPORTATION COSTS INFLUENCE THE FLEXIBILITY TO BALANCE SUPPLY AND DEMAND

7.1 'Spheres of Influence' for Various Supply Sources

For many years, world gas markets consisted of a series of isolated pipeline or LNG trade pairings with little communication among them. The rigidities of the long-term contract with its dedicated links of supply sources, tankers and receipt terminals made it difficult to initiate short-term or spot transactions. Pipelines, with their inflexible physical links between sources and markets were, if anything, even more regionally constrained. The result was that international gas trade operated within a series of isolated regional markets with little or no communication among them.

These rigid patterns began to break up in the 1990s as LNG surpluses in the Asia Pacific market and uncommitted receipt terminal capacity – especially in the United States – made short-term transactions possible. While still small as a percentage of total international trade, these short-term transactions began to create price-driven linkages outside the traditional restricted regional markets. Thus a real 'world gas market' began to emerge.

But a 'world gas market' should not be confused with the much more flexible world oil market. The high costs of LNG transportation still protect some regional supply/demand linkages from interregional competition. This tends to lead to an environment in which certain sources enjoy a sphere of influence for certain markets.

Figures 7.1, 7.2 and 7.3 illustrate tanker transportation costs (using 138,000 cubic metre tankers) for various Atlantic Basin, East of Suez and Pacific Basin trades (including possible western South America trades to the North American West Coast). Only Trinidad in the Atlantic Basin has lower transport costs to the USA than to Europe. The Middle East has somewhat lower transportation costs to Southern Europe (Spain) than to Japan, but

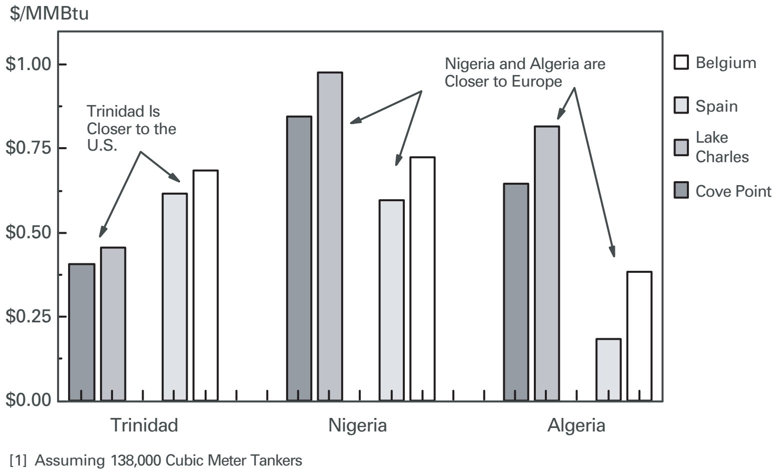


Figure 7.1: Illustrative Tanker Transportation Costs for Selected Atlantic Basin Trades

Source: Author's estimates

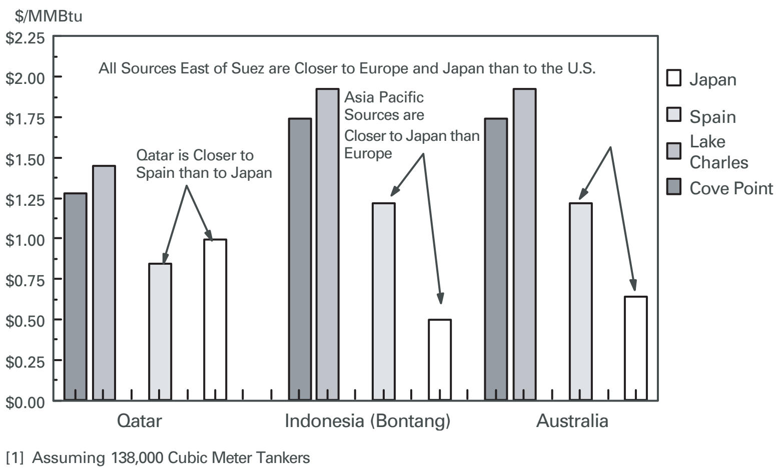


Figure 7.2: Illustrative Tanker Transportation Costs for Selected East of Suez Trades

Source: Author's estimates

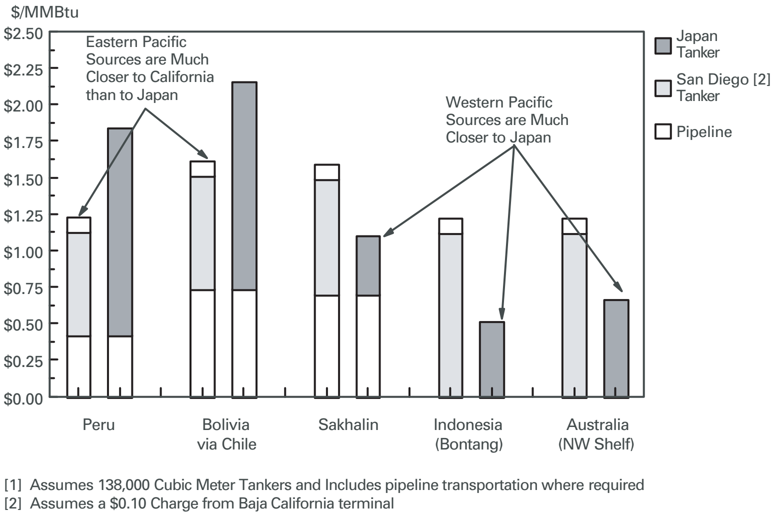


Figure 7.3: Illustrative Tanker Transportation Costs for Selected Pacific Basin Trades

Source: Author's estimates

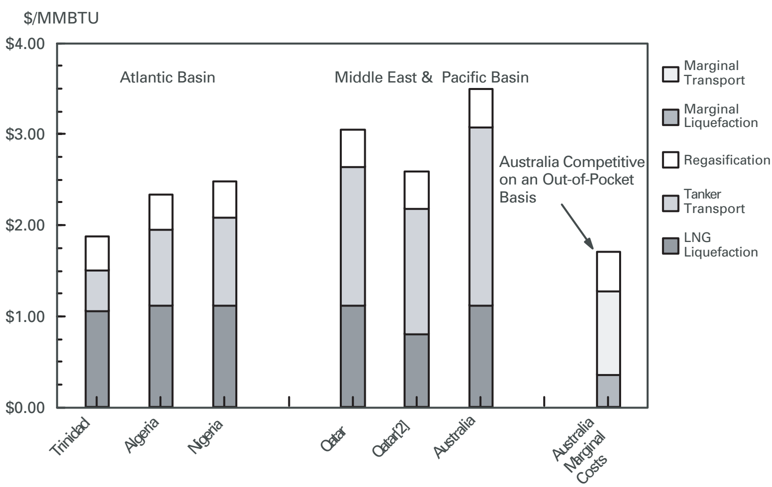
the transport costs (not shown in Figure 7.2) are almost identical to Northern Europe (Belgium). Not surprisingly, eastern Pacific Basin supplies are closer to the West Coast than to Northeast Asia, but Asian supplies are closer to Japan.

These higher transportation costs may be partially offset by the tendency towards higher market prices in the USA and Japan if the Middle East becomes the marginal source of LNG – and thus tends to influence LNG market prices – for North America, Europe and Asia. For example, it takes a $0.53 higher netback in the US Gulf Coast to provide an equivalent netback from a Middle East delivery to Spain. This assumes the Gulf Coast shipment is in dedicated 200,000 cubic metre tankers while all others are in current-sized vessels and that the Gulf Coast port can acccept the larger tankers. (The saving from using the larger tankers to the Gulf Coast would be about $0.14/MMBtu). And it would take a $0.21 premium for Belgium and a $0.17 premium for Japan to provide the same netback.

Although short-term transactions have moved over very long distances (a 1997 shipment from the Northwest Shelf in Australia to Everett travelled more than half way around the world), these depend on a willingness to apply marginal cost[1] economics to the transaction in the face of surplus capacity. For fully allocated cost transactions that are expected to earn their anticipated return on investment, the effective shipment distances are much shorter.

Figure 7.4 shows the costs[2] of transportation (including liquefaction, tanker transport and regasification) for selected sources of supply to the US Gulf Coast. Obviously, the Atlantic Basin (including the Mediterranean) enjoys a substantial transportation advantage over the Middle East and Pacific Basin sources. Trinidad shows the lowest costs of all, and Venezuela (not shown), if and when it develops an LNG export project would be similarly situated. However, its costs would be higher since it would require a larger investment in greenfield infrastructure.

Both the Middle East and the Pacific Basin are more distant from US markets and pay a corresponding transportation penalty to Atlantic Basin sources. The Australia/US short-term transac-



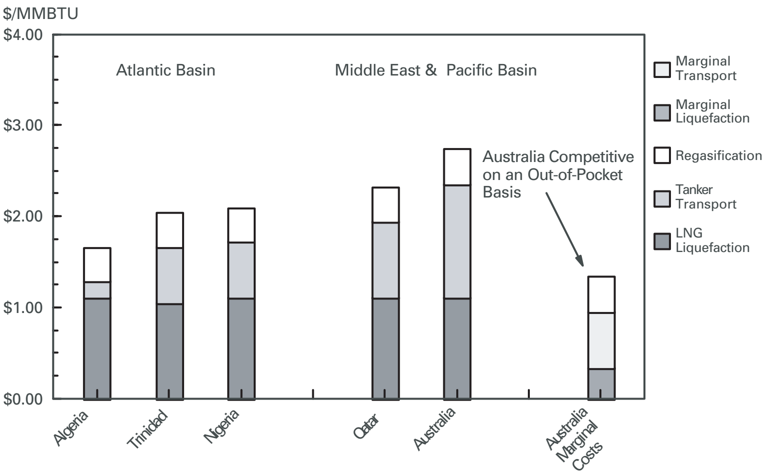
[1] Includes Liquefaction, Transport and Regasification for Expansion Trains: 138,000 Cubic Meter Tankers
[2] Assuming 7.5 MMT Trains and 200,000 Cubic Meter Tankers

Figure 7.4: Illustrative Transportation Costs to a US Gulf Coast Terminal – Assuming Expansion with 3.3 MMT Trains

Source: Author's estimates

tion is illustrated by including only out-of-pocket liquefaction and tanker costs (together with fully allocated regasification costs) in the transportation estimate. The ability of LNG to compete under surplus conditions, even from distant sources, is illustrated by the degree to which the fully-allocated cost estimate from Australia is reduced by including only marginal cost elements.

Figure 7.5 provides a similar evaluation of transport costs to Europe (using Spain as a market destination). Again the Atlantic Basin sources are lower in cost than the Middle East or Pacific Basin sources, although Qatar is only slightly more costly to Spain than is Nigeria. Also, the marginal costs of Pacific Basin LNG make it competitive for spot markets during surplus conditions.



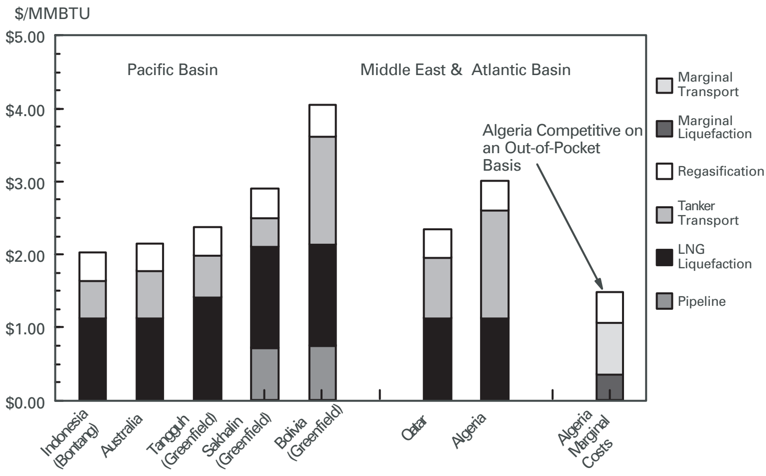
[1] Includes Liquefaction, Transport and Regasification for Expansion Trains: 138,000 Cubic Meter Tankers

Figure 7.5: Illustrative Transportation Costs to a Spanish Terminal – Assuming Expansion with 3.3 MMT Trains

Source: Author's estimates

Except for an early contract from Abu Dhabi, Northeast Asia relied almost entirely on Pacific Basin sources – Alaska, Australia, Brunei, Indonesia and Malaysia – until the mid 1990s. However, with expansion of the Abu Dhabi facility and new greenfield LNG plants in Qatar and Oman, the Middle East has been supplying an increasing portion of Northeast Asia's LNG requirements since that time.

The cost increases involved in Asia's moving to Middle East supplies are not as dramatic as would be the case of a similar transition in the USA, as is evident from Figure 7.6. Compared with new greenfield projects that have at least some contract coverage, shipments from a Qatar expansion are somewhat more costly than Indonesia's Tangguh, but somewhat less so than Sakhalin II. The latter has a comparatively short tanker haul to



[1] Includes Liquefaction, Transport and Regasification for Expansion Trains: 138,000 Cubic Meter Tankers

Figure 7.6: Illustrative Transportation Costs to a Japanese Terminal – Assuming Greenfield or Expansion with Two 3.3 MMT Trains

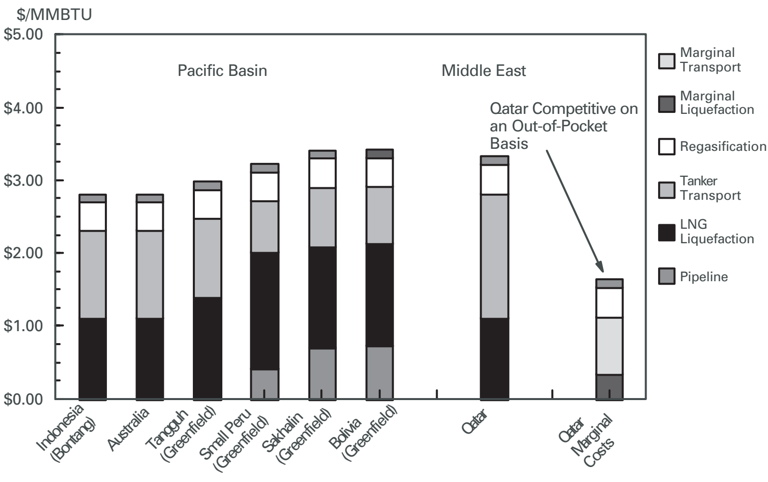
Source: Author's estimates

the Japanese market but suffers from the need to pipe gas from the field over 500 miles to an ice-free port for liquefaction.

Until the November 2003 fall of the Bolivian government – in large part because of its proposed LNG project for US West Coast markets – Bolivia was a prime candidate for new LNG facilities. However, trans-Pacific shipments from Bolivia to Japan would have been quite costly, both because of the long tanker haul across the Pacific and because of the cost of pipelining the gas to a coastal liquefaction plant.

Shipments from Algeria are significantly more costly than from the traditional Pacific Basin sources. However, in the summer of 2003 Algeria made spot sales to Northeast Asia. The out-of-pocket cost of this movement from surplus Algerian supplies was quite competitive, as is evident in Figure 7.6.

The efforts to site an LNG receipt terminal on the West Coast, either in California or across the border in Mexico, have led to a number of proposals for supply both from expansion at existing sites and from new greenfield facilities. Figure 7.7 summarises the transportation costs for selected supply sources. Expansions of existing plants in Indonesia or in Australia appear to provide lower costs than any of the four greenfield facilities shown in the Figure. However, both Tangguh and Sakhalin have 'starter contracts' with Asian markets and thus are in a position to accept somewhat lower netbacks for sales to the West Coast (and are in active negotiations as of this writing) than they might have if West Coast sales were the sole option available. The Bolivian and Peruvian projects, on the other hand, are predicated



[1] Includes Pipeline to Plant, Liquefaction, Transport and Regasification and a $.10 Pipeline Rate to San Diego; Peru Single Train

Figure 7.7: Illustrative Transportation Costs to California – Assuming Greenfield or Expansion with Two 3.3 MMT Trains

Source: Author's estimates

on the development of a North American West Coast market and presumably would have to take a more disciplined view of project economics to proceed. Shipments from a Middle East expansion, while clearly more costly than the nearer Pacific Basin sources, still appear to be in the same ball park as the new greenfield projects.

7.2 LNG 'Basis Differentials'

The high costs of transportation to more distant markets, such as the US Gulf Coast or Northeast Asia are partially offset by a tendency for these markets to have higher landed prices for LNG, particularly if the Middle East is to become the marginal source of LNG to world markets. In the USA, Henry Hub in Louisiana has become the price reference point for US gas markets. Prices in other markets are related to Henry Hub prices by means of 'basis differentials' (See Figure 4.6). These tend to reflect the costs of transportation between Henry Hub and the market in question. Actual basis differentials can be higher or lower than those that transportation costs would imply depending on the relative strength or weakness of the market in question.

Similarly, it is possible to conceive of a series of LNG basis differentials, reflecting the costs of transporting LNG from the Middle East to the various market terminals. Figure 7.8 illustrates what these LNG basis differentials might look like, assuming transportation costs in typical 138,000 cubic metre tankers.

The high costs of transportation from the Middle East to the US Gulf Coast have led Qatar to consider the use of larger LNG liquefaction trains and larger tankers to minimise costs. If Qatar were to supply the Gulf Coast on long-term contracts with dedicated larger tankers, it would tend to reduce the basis differential to that market. Figure 7.8 shows that this development, using 200,000 cubic metre tankers, would reduce basis differentials by about $0.14.

Land-based basis differentials are a standard element of US gas market trading. While they can be volatile, a typical pipeline basis differential from Henry Hub to the Mid Atlantic states where Cove Point is located, is about $0.60. Interestingly enough, when US LNG prices are in equilibrium, the 'cost' of diverting LNG from the Gulf Coast (as reflected by the LNG

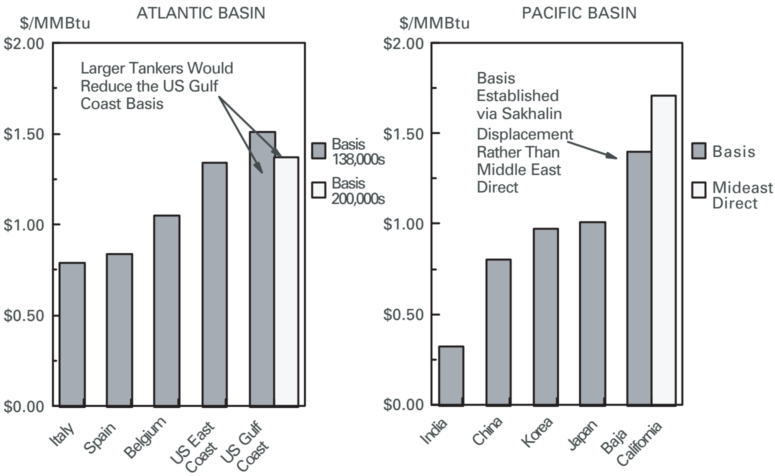


Figure 7.8: Illustrative Basis Differentials Assuming the LNG Hub is Set in the Middle East – Assuming 138,00 Cubic Meter Tankers

Source: Author's estimates

basis differential) is a *negative* $0.17. When Gulf Coast prices are in equilibrium with the Middle East using larger tankers, the 'cost' is still a *negative* $0.03. This indicates the powerful incentive to locate terminals on the upper East Coast at the end of the pipeline.

As yet there are no receipt terminals on the US or Mexican West Coasts, but several proposals are under active study. The West Coast basis differential is unlikely to be set by direct shipments from the Middle East to the West Coast, since several Pacific Basin suppliers to the Northeast Asian market would be able to deliver gas to that market more cheaply than Qatar. Figure 7.8 shows a comparison between the differential that would be set by delivering gas directly from Qatar versus a differential that would be set by displacement of Sakhalin gas from Japan to Baja California. If Sakhalin accepts the same netback from Baja than it would otherwise get in parity with Middle East shipments to Japan, it could reduce the West Coast direct basis differential by $0.31.

7.3 The Emergence of Arbitrage to Link Prices Among Regions

An important part of this new trading pattern is the emergence of arbitrage between markets. This phenomenon is the furthest developed within the Atlantic Basin, primarily involving supplies from Trinidad and Nigeria and markets in the United States and Europe (primarily in Spain). Thus gas moves to whichever market will offer the highest netback and flows shift accordingly. Another pattern of arbitrage has developed between Northeast Asian markets and Atlantic Basin markets via shipments from the Middle East. Middle East suppliers, principally Qatar, are in a position to ship either to Asia or to the Atlantic Basin as markets dictate.

Figure 4.2 showed the increase in 'firm' and 'probable' contract commitments between 2002 and 2010 broken down into third-party contract volumes and uncommitted or system volumes. The Figure illustrated that 85% of the incremental volumes are committed on third-party contracts, while only 15% are uncommitted. Figure 7.9[3] illustrates that the bulk of the

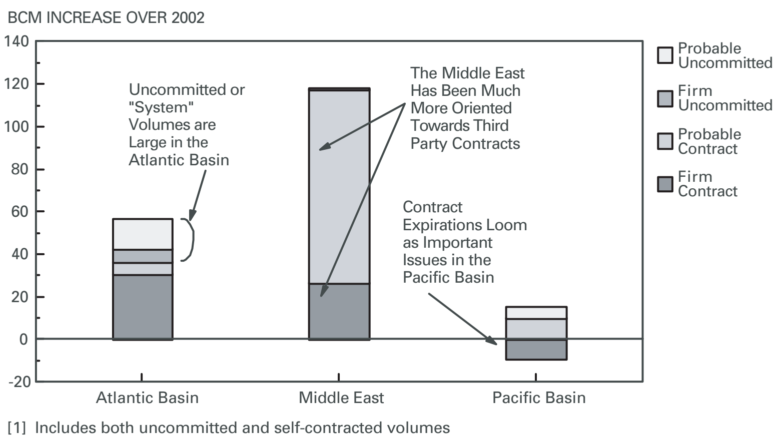


Figure 7.9: New Firm and Probable Contract Volumes – Showing the Regional Balance between Third-party Commitments and Uncommitted[1] Volumes

Source: Author's estimates

'uncommitted' volumes is located in the Atlantic Basin, where arbitrage has been the most active.

The 'uncommitted' volumes include self-contracting[4] where the seller contracts with his own marketing affiliate in order to achieve downstream integration. If these system sales are intended to serve previously-determined integrated markets, they may be less flexible than their appearance as 'uncommitted' volumes would suggest. For example, several of the companies that have self-contracted have acquired regasification terminal capacity in several markets, clearly intending to move LNG through their own integrated systems much as they might earlier have done with third-party contracting.

Arbitrage enables the trading company to divert cargoes to those markets that provide the highest netbacks. But the capability to arbitrage requires sufficient excess capacity in tankers and receipt terminals to take advantage of market opportunities when they occur. Some of the excess capacity is the result of the normal imbalances between supply and demand which can be utilised when available to seek out the best netbacks. Figure 5.16 indicated that the average length of tanker voyage for short-term volumes was considerably longer than the average length of voyage for contract sales, indicating the ability to use surplus tanker capacity to reach markets that might be difficult to serve economically on long-term contracts. The surplus receipt capacity in the terminals in the USA was in part a lingering result of the collapse of the Algeria/US trade in the 1980s.

But companies can elect to create excess tanker and terminal capacity in order to take advantage of arbitrage trading. However, the deliberate creation of excess capacity is not a costless exercise. To create an annual surplus capacity in receipt terminals of 25% involves about a 10% increase in the costs of regasification.

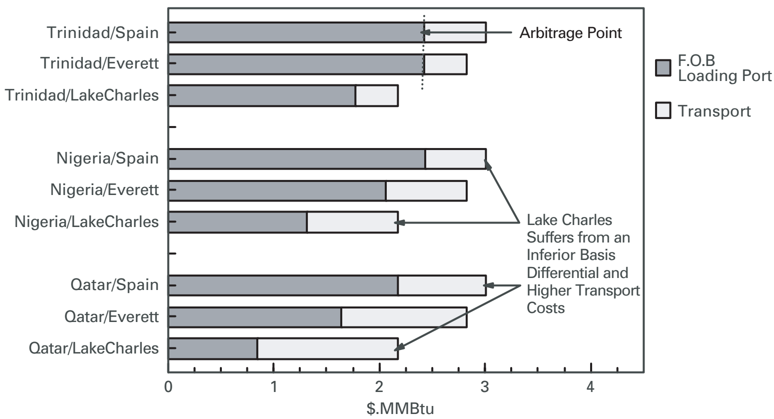
The creation of excess tanker capacity through purchases of newbuild tankers is somewhat more costly. A 25% spare capacity may cause about a 21% increase in tanker costs. However, the short-term tanker trading has tended to concentrate on used tankers that are no longer in their original service. For such vessels the costs can be considerably reduced below newbuild excess capacity levels.

7.4 Arbitrage in the Atlantic Basin

Much of the interregional arbitrage that has occurred to date has been in the Atlantic Basin primarily involving Trinidad and Nigeria as suppliers and the USA and Europe (primarily Spain) as market destinations. Figure 7.10 provides an example of how this arbitrage operates, using one of the most common Atlantic Basin arbitrage patterns. It assumes a case in which a Trinidad shipper is indifferent as to whether he ships to Huelva in Spain or Everett on the US East Coast, since he receives the same netback from either market. The case assumes his ex-ship price in Huelva is \$3.00, although he would receive only \$2.82 in Everett – a lower price that is offset by his lower transportation costs.

Lake Charles, on the US Gulf Coast suffers from two disadvantages relative to Everett. It forfeits Everett's pipeline basis differential and it is farther from supply sources. Thus in this case, the Trinidad shipper may be indifferent to Huelva or Everett, but both provide superior netbacks to Lake Charles.

When the arbitrage is set between Everett and Huelva, both Nigeria and Qatar achieve higher netbacks in Spain than they do



Assuming that a \$3.00 Ex Ship Price from Trinidad at Huelva Sets the Atlantic Basin Arbitrage, Fully Allocated Tanker Costs

Figure 7.10: Netbacks to Trinidad, Nigeria and Qatar Loading Ports from Spanish and US Terminals

Source: Author's estimates based on World Gas Intelligence Price Reports

in either Everett or Lake Charles. As prices shift on both sides of the Atlantic, the arbitrage balancing points shift with them and the LNG shipments tend to seek out the better netbacks.

When the United States first experienced its 'gas price shock' in Fall and Winter of 2000, it appeared that anyone with access to a US terminal could make substantial profits by buying in the surplus LNG market and selling into the high-priced shortage market in the USA. Many of the proposed new North American terminal proposals appeared during this period and frequently involved US marketing companies without upstream LNG assets.

However, the following Spring gas prices collapsed as market surpluses developed and access to US terminal capacity no longer appeared so attractive. Figure 7.11 illustrates the sharp change in perceived profitability of the merchant terminals (as well as of merchant sellers and integrated operations) between July 2000/June 2001 and the following year. The netbacks are based on the pricing experience of the Lake Charles terminal during the period and assume operation at design capacity; on this basis the Everett terminal did even better. Actual US terminal throughput was significantly lower, reflecting competition with Europe for cargoes.

During 2001, the Atlantic Basin arbitrage worked in favour of Europe where prices remained stronger. Then in late 2002,

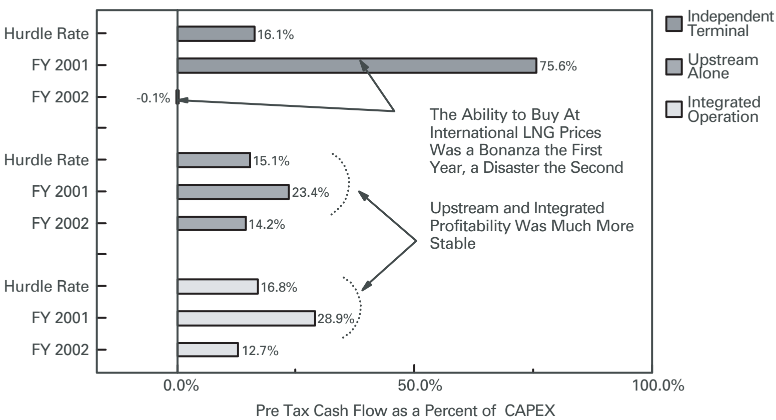


Figure 7.11: Pre-Tax Cash Flow as a Percent of Capital Investment

Source: Author's estimates

Tokyo Electric ran into difficulty with its nuclear facilities and shut down seventeen plants. This upset LNG markets and tanker availability again affecting the market arbitrage in the Atlantic Basin. The effect on US terminal capacity operation is illustrated in Figure 7.12.

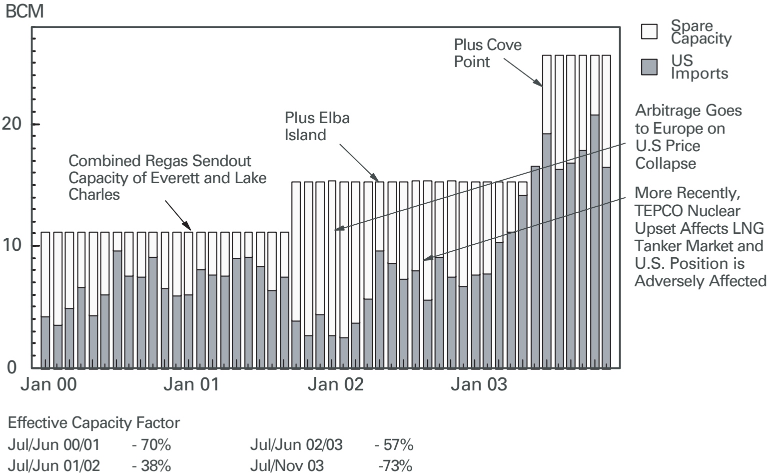


Figure 7.12: Comparison of US LNG Imports with Terminal Capacity

Source: based on EIA data

Figures 7.13, 7.14 and 7.15 illustrate the netbacks from three selected markets to three suppliers during the three periods. In December 2000, when US prices were very strong, Trinidad, Nigeria and Qatar all could achieve higher netbacks from the US Gulf Coast (assuming they had access to terminal capacity) than they could shipping to Spain or in Qatar's case to Japan.

But by the following September, US prices had collapsed and both Trinidad and Nigeria preferred shipments to Spain while Qatar preferred Japan. The strengthening of the Asian markets following Tokyo Electric's nuclear shutdown caused each shipper to prefer a different market – Trinidad, the US Gulf Coast; Nigeria, Spain; and Qatar, Japan.

Prices have fluctuated substantially on both sides of the Atlantic, providing ample opportunity for arbitrage. Figure 7.16 illustrates the netback performance from actual prices in selected

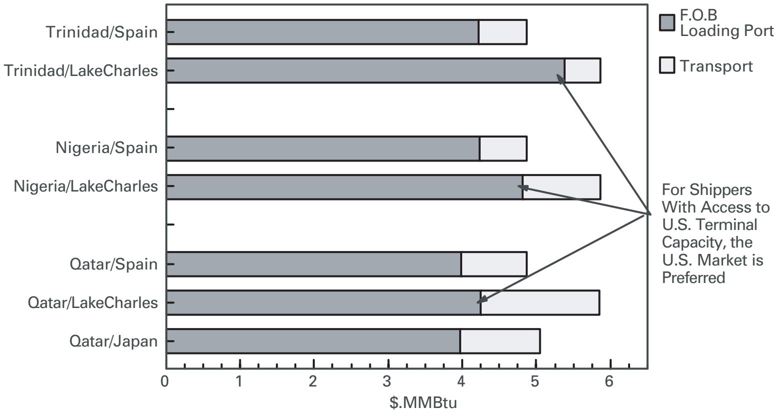


Figure 7.13: Netbacks to Trinidad, Nigeria and Qatar Loading Ports from European, US and Japanese Terminals – December 2000

Source: Author's estimates based on World Gas Intelligence Price Reports

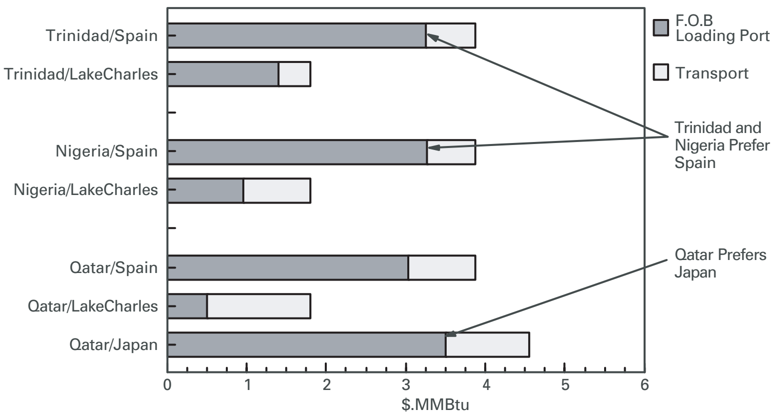


Figure 7.14: Netbacks to Trinidad, Nigeria and Qatar Loading Ports from European, US and Japanese Terminals – September 2001

Source: Author's estimates based on World Gas Intelligence Price Reports

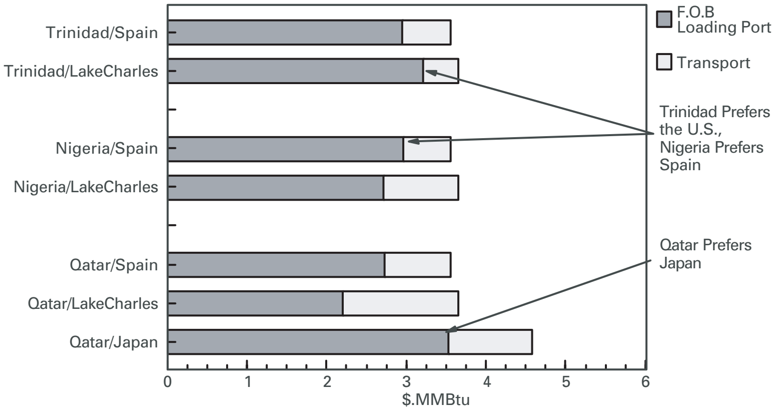
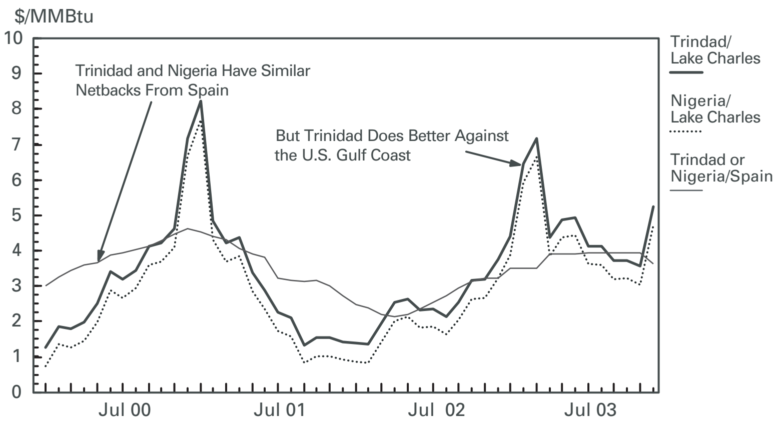


Figure 7.15: Netbacks to Trinidad, Nigeria and Qatar Loading Ports from European, US and Japanese Terminals – November 2002

Source: Author's estimates based on World Gas Intelligence Price Reports



[1] US Prices are Market Prices; Spanish Prices are Import Prices and Include Imports with Relatively Stable Contract Terms

Figure 7.16: Illustrative Netbacks for Selected Atlantic Basin Arbitrage Patterns

Source: Author's estimates based on World Gas Intelligence Price Reports

markets from 2000 through 2003. The time series captures the changing trends in netback advantage that have been illustrated for selected months in Figures 7.13, 7.14 and 7.15.

US Gulf Coast prices are derived from Henry Hub market prices by allowing for a $0.35 regasification charge and a $0.10 basis differential from the terminal to Henry Hub. Spanish prices are LNG import prices as liquid. Since Spanish imports include a substantial quantity of contract volumes with their formula prices, the two price series are not completely comparable. The Spanish import prices are inherently more stable than US market prices.

Since the transportation costs from both Trinidad and Nigeria to Spain are virtually identical, the two suppliers net back similar prices from that market. Trinidad enjoys a transportation advantage to Lake Charles and thus would be expected to enjoy a higher netback than Nigeria.

The netbacks of Figure 7.16 assume tanker transportation at fully allocated transportation rates. In times of tanker surpluses, tanker rates will be discounted, shifting the arbitrage balancing point to more distant supplier locations.

7.5 Arbitraging the Atlantic and Pacific Basins via the Middle East

The current lack of any LNG terminals on the Eastern side of the Pacific has eliminated the possibility for an Atlantic Basin style of arbitrage to develop in the Pacific Basin. But the Atlantic Basin and the Pacific Basin are linked through the Middle East, which can act as a swing supplier to both Asia and the Atlantic Basin. This is illustrated in Figure 7.17, which shows the netbacks to Qatar from the US Gulf Coast, Spain and Japan.

The Japanese price data, like the Spanish price data, are for all LNG imports and thus include the stabilising effect of contractual volumes. When US prices have been strong, they have provided the best netbacks to the Middle East. Japan usually provides better netbacks than does Spain, but the fact that Japan has a much more limited short-term market tends to focus the Middle East trading volumes on Europe.

Japanese prices, based on the traditional crude oil linkage formulas that have been utilised in that country, have tended to be

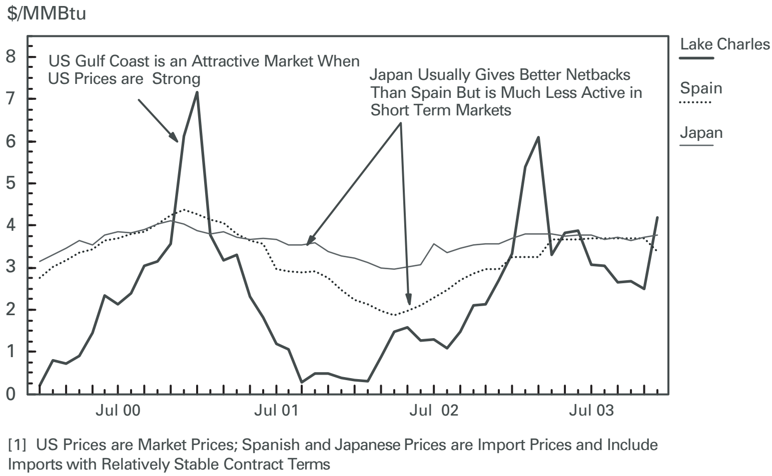


Figure 7.17: Illustrative Netbacks from the US Gulf Coast, Spain and Japan to the Middle East

Source: Author's estimates based on World Gas Intelligence Price Reports

among the world's highest. The expiration of a significant number of Australian and Indonesian contracts toward the end of the decade has the potential to weaken Asian prices and to change the relative shape of the arbitrage curves of Figure 7.17.

7.6 The Potential for Arbitrage in the Pacific Basin

The active pursuit of LNG terminal options both on the US West Coast and in Mexico for both Mexican markets and for transshipment to California raises the possibility of a Pacific Basin arbitrage similar to that in the Atlantic. For a number of reasons, this market will behave quite differently from the Atlantic Basin market. The LNG basis differentials will be based on displacement of Asia Pacific supplies to Northeast Asia, rather than by direct shipment from the Middle East. For example, a Sakhalin displacement ($0.31 cheaper than direct delivery from the Middle East) has been used in Figure 7.18 to establish the basis differential for Baja California relative to the Middle East. In addition, distances are longer for the Pacific Rim

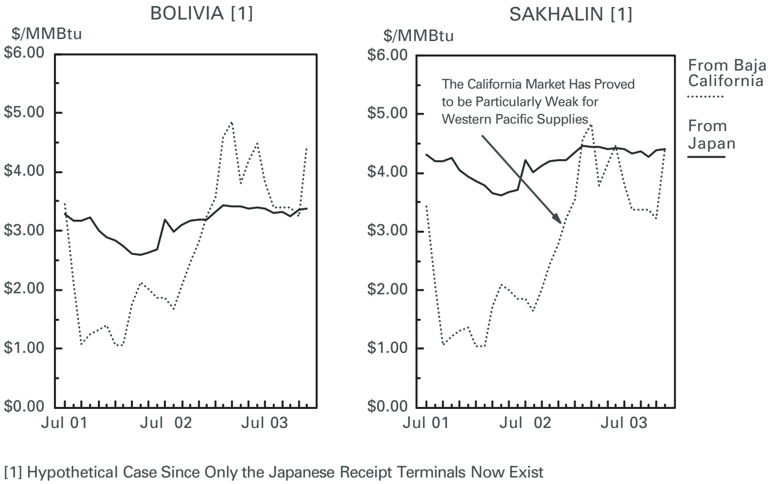


Figure 7.18: Illustrative Netbacks to Sakhalin and Bolivian Plants from Japan and Baja California – Assuming 138,000 Cubic Metre Tankers

Source: Author's estimates based on World Gas Intelligence Price Reports

source/market pairings with the result that it requires much more tanker capacity to take advantage of an arbitrage situation.

One of the key patterns of the Atlantic Basin arbitrage has been the ability to switch cargoes between the Everett terminal on the East Coast and a Spanish terminal. Now that Cove Point is operational the same logic will apply for that terminal. For Trinidad to divert cargoes from Everett to Spain requires a 53% increase in tanker capacity to handle the same volume. For Nigeria to divert cargoes from Spain to Everett requires only a 43% increase. The normal cost penalty for each is about $0.20 for the switch. Obviously the ability to arbitrage is in part a function of the relative strength of the tanker market.

In contrast, to switch cargoes across the Pacific would take twice as many tankers for a Bolivian shipment to Japan as it would to Baja California, 2.1 times as many for a Tangguh to switch from Japan to Baja, and 2.5 times as many for a similar Sakhalin switch. For Bolivia, the cost penalty would be $0.69, for Tangguh $0.52 and for Sakhalin $0.42. Although the higher transportation costs might be at least partially offset by higher basis differentials

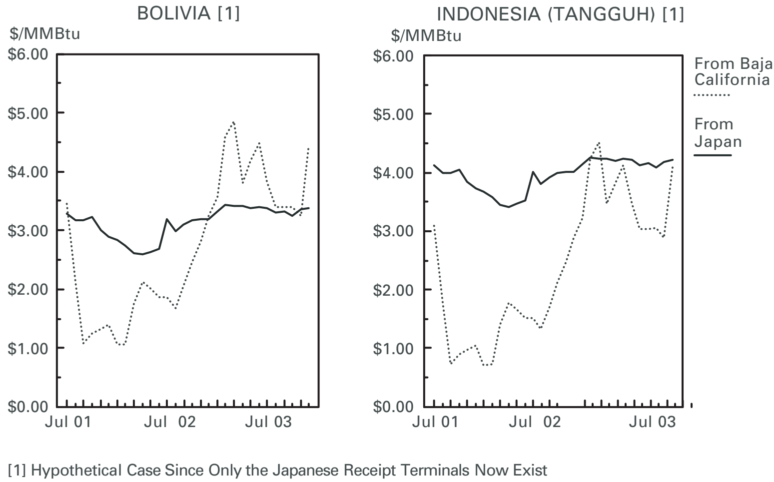


Figure 7.19: Illustrative Netbacks to Indonesian and Bolivian Plants from Japan and Baja California – Assuming 138,000 Cubic Metre Tankers

Source: Author's estimates based on World Gas Intelligence Price Reports

on the North American West Coast, the requirement for much larger tanker capacity during strong tanker markets would pose a special problem for Pacific Basin arbitrage.

Figures 7.18 and 7.19 compare the hypothetical (since three of the four locations do not yet exist) arbitrage patterns for the recent past. The data for the period from January 2000 to June 2001 has been omitted since the California energy crisis during that period severely distorts the comparison.

Clearly, the Bolivian project has run into serious political difficulties with the fall of the Government that sponsored it and the Peruvian project now appears as if it may be dedicated to purely Mexican trade via the West Coast Lazaro Cardenas terminal. Absent sources of LNG on the West Coast of South America, the Pacific Basin arbitrage remains an abstraction.

Notes

1. Marginal costs cover out-of-pocket cash costs but do not recover the fixed charges for capital recovery or return on investment.

2. All costs shown in Figures 7.4 through 7.7 are illustrative using formula costs for the trade rather than project-specific costs from company records.
3. Since Figure 7.9 focuses on plateau commitments, it does not isolate 'ramp-up' volumes, which provide additional flexible gas for arbitrage.
4. The distinction between self-contracting and third-party contracting is itself somewhat ambiguous. In several cases (particularly in the Middle East), where the producing joint venture acts as the seller, the sale is downstream to one of the parties of the venture. In such a case, this analysis has treated them as third-party sales.

8. REGIONAL GAS DEMAND GROWTH AND ITS INFLUENCE ON FUTURE TRADE PATTERNS

8.1 The Growth of Natural Gas Demand – The Prime LNG Import Targets

All forecasters anticipate a rapid growth in worldwide natural gas demand, and as a result a substantial increase in world gas trade. The International Energy Agency in its *World Energy Outlook 2002* foresees a demand growth of 1,727 BCM between 2000 and 2020, an amount roughly equivalent to 67% of the world's gas consumption in 2002. The US Energy Information Administration in its *International Energy Outlook 2003* anticipates a similar growth – 60.2 quads (1,705 BCM) between 2001 and 2020.

Only 23% of world gas consumption in 2002 was imported and only 26% of that was in the form of LNG. Thus forecasts of gas demand or even of gas trade do not necessarily indicate how rapidly LNG is likely to grow nor where it is most likely to be utilised.

The EIA's estimates are broken down by broad groups of countries. About one-third of the increase in demand is anticipated to take place in countries that are expected to be self-sufficient – such as Canada, the Netherlands, or the former Soviet Union – or are expected to rely solely on pipeline imports. Of the remaining two-thirds of the increase, 10% is included in broad groups and is not detailed (including such significant LNG importers as Taiwan or Spain, for example). But 57% of the growth is expected to occur in specified countries where LNG is an option.

The EIA does not attempt to apportion this growth in gas demand among indigenous production, pipeline imports or LNG, so it does not supply a forecast of LNG as such. Figure 8.1 shows the incremental growth in gas demand between 2001 and 2020 for groups of countries.

Some, such as the USA, Mexico and the UK have tended to be dependent on domestic or imported pipeline supply, but now are entering the market for LNG to supplement deficiencies in

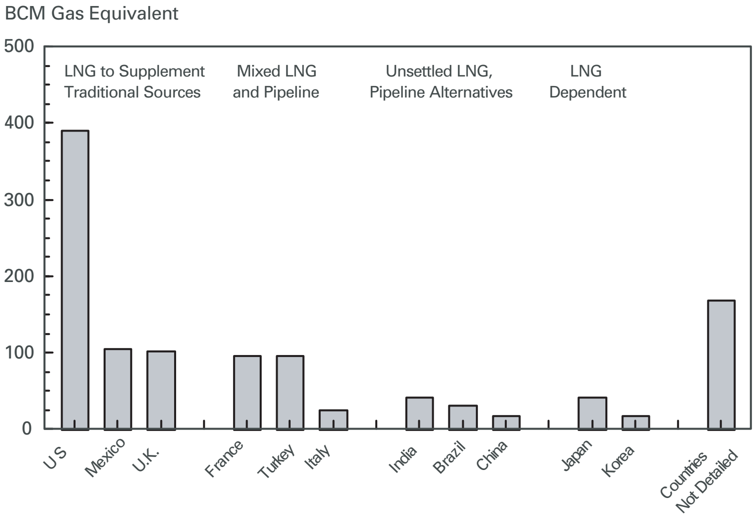


Figure 8.1: Forecast of Growth in Total Gas Demand 2001/2020 by Potential LNG Importing Countries

Source: EIA International Energy Outlook, 2003

domestic production. Others, such as France, Turkey and Italy, have utilised both pipeline imports and LNG for their markets and will likely continue to utilise both options.

Some of the larger potential natural gas markets – India, Brazil and China – are still deliberating how much gas to import and in what form. The only major markets in Figure 8.1 that the EIA has detailed that have been totally LNG-dependent are Japan and Korea. While these countries were the engine of LNG growth in recent years their demand has slowed and they are also considering the possibility of pipeline imports.

The International Energy Agency has been somewhat more explicit about increases in international trade in its *World Energy Outlook 2002*. In its Figure 3.13, the IEA shows 'Net Inter-Regional Gas Trade Flows, 2030'. By converting the estimates on the graphs into Average Annual Increases in flows and specifying whether the flow in question is likely to be purely LNG (such as Africa/North America) or mixed LNG/Pipeline (such as Africa/Europe), it is possible to get some idea of where the IEA anticipates that the major flows will occur.

Figure 8.2 summarises the flows as either LNG or mixed LNG/Pipeline into the principal importing regions (excluding pure pipeline trades such as those from the former Soviet Union to Europe). While North America has shown little historical growth in inter-regional imports, its increases – all as LNG – for the forecast period will become the largest. Europe has been heavily dependent on the former Soviet Union for pipeline imports (not included in the Figure), but will substantially increase its dependence on other inter-regional imports. The North African trade has been a mixture of trans-Mediterranean pipelines and LNG, but its growing reliance on the Middle East and on Latin America will be heavily oriented towards LNG.

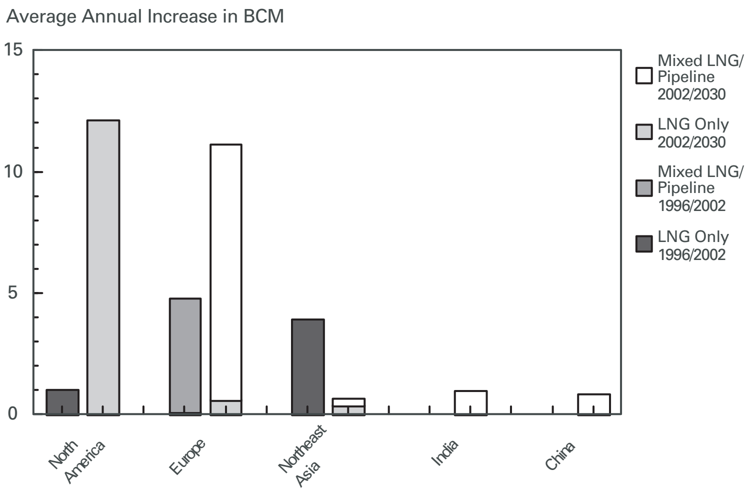


Figure 8.2: Forecast of Average Annual Increase in Net Interregional Imports to 2030

Source: IEA World Energy Outlook, 2002

The IEA sees a slowing of the growth in LNG or LNG/Pipeline trade to Northeast Asia. Both India and China emerge as important markets for inter-regional trade, although they remain small compared to North America and Europe. While LNG should be the early winner, the possibility of overland pipelining to India remains if the political climate improves, and China has seriously considered pipeline supply from East Siberia.

Figure 8.3 summarises the same information by exporting regions. The Middle East has increased slightly more rapidly than Africa between 1996 and 2002, but will gain significantly during the forecast period. Latin America will also increase its average level of exports over the period. The Asia Pacific region, which dominated export supply until the late 1990s, has slowed considerably since 1996. The IEA does not expect it to increase its exports that significantly in the forecast period.

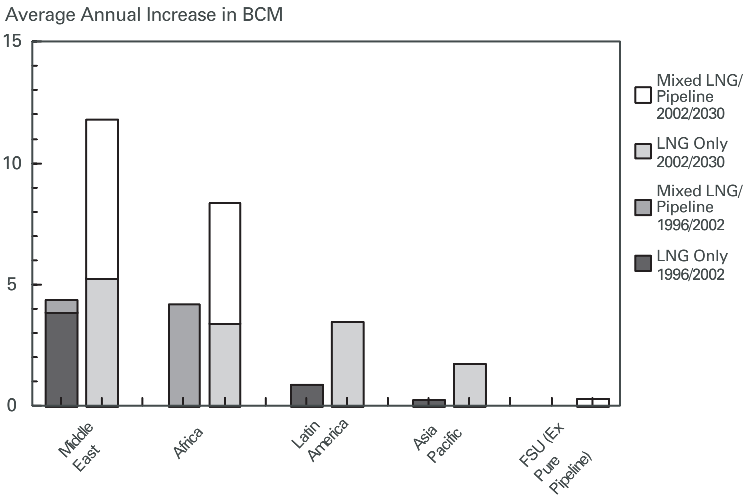


Figure 8.3: IEA Forecasts of Average Annual Increase in Net Interregional Exports to 2030

Source: IEA World Energy Outlook, 2002

The small export potential from Russia (again excluding the very large pipeline flows to Europe) will enter the LNG/Pipeline supply figures for its potential Sakhalin and East Siberian exports and the possible development of LNG exports from Western Siberia.

Some indication of the prime LNG targets comes from the trends that have been established by recent trading patterns. With the collapse of the US market in 1980, the focus of international LNG shifted from the Atlantic Basin to the Pacific Basin. Between 1980 and 1996, Japan, Korea and Taiwan accounted for 80% of all growth in LNG trade, with Japan alone accounting for 56% of it. Figure 8.4 illustrates the dominant role of Japan, Korea and Taiwan during this period. Now, both India and China are poised to contribute to the growth of the Asia Pacific region.

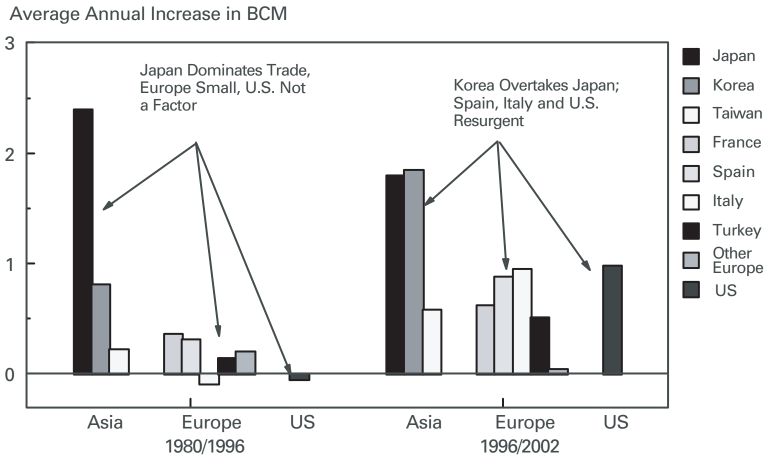


Figure 8.4: Average Annual Increase in LNG Imports by Country for Two Selected Periods

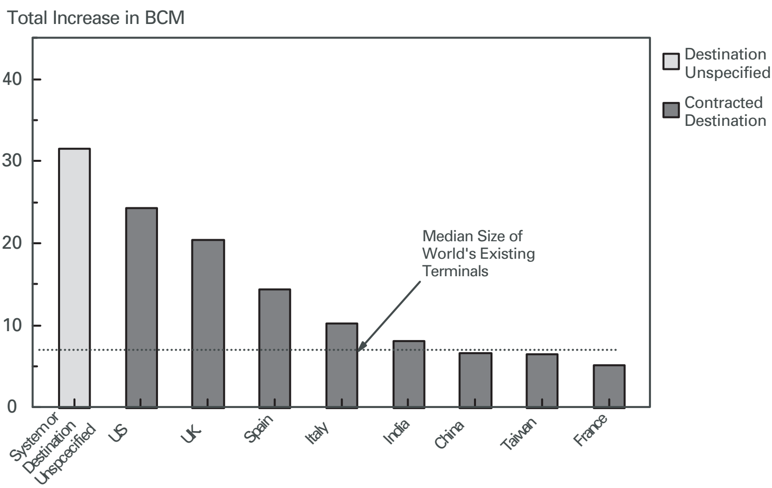
Source: Cedigaz data

Beginning in the mid 1990s, the Japanese economy began to slow, while interest in LNG revived in countries such as the United States, Italy and Spain. Thus Korea overtook Japan in growth and the Atlantic Basin market became much more important. Now, the United Kingdom seems poised to become a major LNG importer as it finds itself with growing demand and poorer prospects for meeting its requirements from traditional North Sea sources.

In summary, the patterns of potential LNG trade indicate the emergence of North America, the UK, India and China to join the ranks of major importers such as Japan, Korea, Spain, France, Taiwan and Italy. The historic growth of the Asia Pacific as a supply region is expected to slow, while the Middle East, Africa and to a lesser extent Latin America emerge as more important incremental exporters.

8.2 The Implications of Contract Commitments on Market Destinations

Some indication of the expected destination of increased LNG imports is available from long-term contract commitments. Figure 8.5 shows the increase in contract commitments by major destinations for increased deliveries by 2010 over 2003 levels. The increase in commitments for five countries – the USA, the UK, Spain, Italy and India – are all larger than the median size of the world's receipt terminals, giving some indication of the pressures for new receipt terminal capacity. The increase in three other countries – China, Taiwan and France – is nearly as large as the median terminal size threshold. Japan and Korea, the largest of the recent importers, do not show a significant increase in net import commitments. However, much of that is attributable to the fact that some of their older contracts are coming up for renewal and the net increase in commitment levels is not that large. As their markets continue to grow, additional capacity will probably be needed.



[1] Commitments are meant to include signed contracts, but may also include "heads of agreement" where in the judgment of the author their signing appears likely

Figure 8.5: Destination of the Increase in LNG Deliveries

Source: Author's estimates

The inherent problem in using new contract commitments as a measure of receipt terminal capacity requirements is the 'chicken and egg' problem. Because the capacity does not exist, it is difficult for the buyer to sign up for new supply. In markets such as the USA and India, where new terminals have been difficult to permit and build, contract commitments may not be a true measure of long-term demand for LNG.

8.3 The Prospects for New US Terminals

The US mainland has four existing terminals and there is one additional small one in Puerto Rico. All except the Puerto Rican terminal were built for the first wave of enthusiasm for LNG and were designed for Algerian supply. The new Puerto Rican terminal, with a capacity of 1.9 BCM, is served primarily by Trinidad.

Both Cove Point and Elba Island were closed for more than twenty years, but with the reopening of Cove Point in July 2003, all are now actively importing LNG. During 2003, 75% of the supply for these four terminals came from Trinidad, 11% from Algeria and 10% from Nigeria.

The wave of enthusiasm for LNG in the USA has led to a rash of proposals for new receipt and regasification terminals. East Coast terminals such as Everett have two very strong economic advantages. They are downstream from the major southwest producing areas and thus enjoy a pricing advantage (basis differentials) over the main gas pricing point in Henry Hub, Louisiana. And they are closer to the major LNG supply points, thereby minimising tanker transportation costs.

Unfortunately, it has proved to be extremely difficult – though not impossible – to gain siting approval for such East Coast locations because of local popular opposition. Therefore, Atlantic Basin terminal options seem to have settled on three different alternatives.

1) Gulf Coast locations where the long history with oil and chemical sites minimises local opposition.
2) Foreign locations, such as Nova Scotia, New Brunswick, the Bahamas or Mexico, where siting approvals may be easier to obtain but the gas must be further moved by pipeline.

3) Offshore, where environmental approvals are less stringent.

The Gulf Coast terminal options are easier to approve and integrate into the pipeline grid, but they forfeit the basis advantage and the shorter distance from sources that favour the East Coast. The foreign locations lose some of their basis advantages through additional pipeline costs to reach the grid and they can easily overload local markets, thereby depressing prices. The offshore locations have come into greater favour with the November 2002 enactment of the Deepwater Port Act Amendment (DWPA),[1] which shifts regulatory responsibility for offshore LNG facilities from the Federal Energy Regulatory Commission to the Maritime Administration and the US Coast Guard.

The Pacific Coast has similar siting problems to the Atlantic/Gulf Coasts. The early PacIndonesia project that was supposed to deliver LNG from Indonesia to California in the 1979/1980 time frame, was cancelled for a number of reasons, one of which was powerful popular resistance to siting the terminal in California. Thus, many of the new West Coast LNG proposals are based on deliveries into Baja California and transmission across the Mexican/US border by pipeline.

One of the problems of terminal siting, not only on the East Coast but also in other locations, is the complexity of regulations – Federal, state and local – that impact project approval. Many of these regulations have developed for specific reasons that may not apply to the siting of a new terminal, but must be addressed by the terminal developer before he can proceed.

One of the thrusts of US policy in its restructuring of its gas industry has been the emphasis on 'open access' to transportation facilities. This eliminates monopolistic control of capacity and is a means of encouraging new entrants and enhanced competition. Under such a policy, capacity can still be controlled on a long-term contract but the rights to capacity can be bought and sold making it a part of the market economy.

The initial view of LNG terminal capacity was that it would be treated the same way as pipeline capacity and would be subject to open access regulations. All of the existing mainland terminals, with the exception of Everett (originally an intra-state terminal subject to less Federal jurisdiction), are open access. However, the large producers with LNG assets upstream have argued that they are not willing to invest in downstream terminal capacity unless they can control throughput.

In its 'Hackberry' decision[2] involving Dynegy's proposal for a new terminal (now controlled by Sempra) at Hackberry, LA, the FERC waived the open access provisions. This decision, together with the financial problems of the gas merchants and the obvious risks of investment in a terminal without some upstream control, seems to have shifted the balance of power in terminal projects in favour of the integrated majors and away from the merchants.

The public resistance to onshore terminal siting, when combined with the greater flexibility to locate terminals offshore, has stimulated interest in offshore receipt terminal designs. In Europe, offshore terminals have been proposed in Italy. The most advanced US project is that of ChevronTexaco. Its proposed Port Pelican terminal envisions a deepwater platform 36 miles offshore that would enable the company to utilise existing Gulf gathering and transmission facilities. There are at least six other offshore proposals for Gulf Coast or West Coast terminals.

Two of the more innovative design concepts are the 'Energy Bridge'[3] tanker design originally proposed by El Paso (the design now owned by Excelerate Energy), and the Gulf Coast salt dome gasifiers proposed by Conversion Gas Imports.[4] El Paso placed orders for tankers that have the regasification facilities located on the tanker itself. They thus can deliver the regasified LNG directly onshore via pipeline. The advantages are clearly the proposal's flexibility and the ability to overcome the opposition of local groups. It has several disadvantages. Its high rate discharge system requires that the pipeline grid have the capability to absorb large flows and, while tankers can presumably be scheduled on a shuttle basis to minimise time off line, it probably needs backup storage to cover delays in tanker arrivals. And its higher tanker cost may restrict it to shorter, dedicated runs where the expensive vessels can achieve high capacity operation.

The technology developed by Conversion Gas Imports (CGI) is based on the concept of pumping LNG under high pressure from the vessel through a heat exchanger directly into salt caverns, where it is stored in high pressure gaseous form, thereby avoiding the use of traditional LNG vaporisers and storage tanks.

Salt caverns are widely available in the Gulf Coast and are used for gas and liquid storage. CGI originally proposed using this technology in an onshore Louisiana terminal but the technology is readily adaptable to offshore platform operation as well.

It has proved to be very difficult to determine how many terminals will be built in the USA and where they will be located. Project investment in LNG, both in liquefaction and in receipt terminals, has always been characterised by a great deal of 'gaming' – that is a large number of competitive proposals by sponsors who hope to beat out competitors and exploit a particular opportunity. This has been particularly true in the USA where a far larger number of terminal proposals have been discussed in the trade press than are ever likely to be needed. One trade press analysis[5] in late 2003 listed 26 proposals for new receipt terminals in the USA, Canada, the Bahamas and Mexico (largely for US markets). Since that publication, a number of new proposals have surfaced while a number on the list have been abandoned.

Some measure of the gaming that is going on in North American receipt terminal proposals is shown by the capacity that would be available from these ventures compared to any reasonable expectation of need. Figure 8.6 compares the total capacity of the proposals that appeared active last Fall with

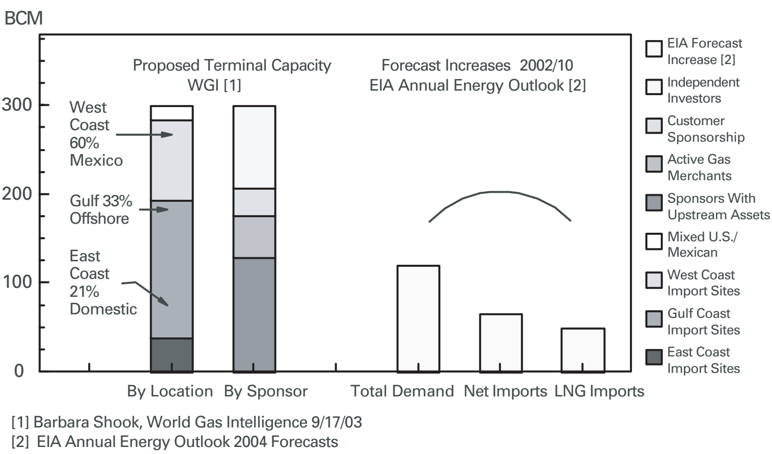


Figure 8.6: Capacity of Proposed New North American Terminals

the forecasts by the EIA in its *Annual Energy Outlook 2004* for the growth in gas demand and in imports between 2002 and 2010. The increase in total proposed LNG terminal capacity is 4.6 times its expected increase in gross LNG imports and even 3 times its projected increase in total gas demand. While the capacity estimates in Figure 8.6 are not current, they may represent something of a high water mark for LNG proposals. There have probably been more projects abandoned in recent weeks than have been added to the list.

The EIA, in its *Annual Energy Outlook*, has made its own estimates of where US terminal expansion will take place by 2010. The details are provided in a separate EIA study[6] that was prepared for an LNG summit held by the Department of Energy in Washington in December 2003.

All four of the US terminals have either recently expanded their capacity or have active expansion plans. As a result, the EIA expects that almost 60% of the increase in LNG imports will be provided by expansion at existing facilities. It also foresees the new sources shown in Table 8.1 for US markets by 2010:

Table 8.1: EIA Estimate of New Receipt Terminal Locations with Expected Import Levels[7]

Location	Annual Import Levels (BCM)
Eastern Gulf of Mexico	8.87
Western Gulf of Mexico	7.39
South Atlantic States	3.48
Florida via the Bahamas	3.29
California via Mexico[8]	5.17

8.4 Other Western Hemisphere

In addition to the Baja California terminal proposals that are at least partially destined for the US market, Mexico is considering terminals for its own markets at Altamira on the Gulf Coast and Lazaro Cardenas on the Pacific side of the country. There is already one small receipt terminal in the Dominican Republic and a proposal for another small Caribbean terminal is under consideration in Jamaica.

There has been active interest in an LNG receipt terminal in Brazil's Northeast near Fortaleza. However, the discovery of a major new gas find in 2003 in the Santos Basin coupled with disappointing performance of the gas markets served by the Bolivia-to-Brazil pipeline appears to have slowed movement on Brazilian LNG imports.

8.5 Europe

Europe opened two new terminals in 2003 – Bilbao in Spain and Sines in Portugal. In addition there are a number of other European terminals and expansions under construction or in the planning stage.

While the Spanish market has shown the most recent active growth in Europe and the plans of new terminal capacity for Italy, Spain and France are substantial, the market with the most ambitious expansion plans is the United Kingdom. An LNG peak shaving plant at the Isle of Grain is being converted to a receipt terminal and both ExxonMobil and Petroplus have active plans for projects at Milford Haven in Wales.

Figure 8.7 compares the firm and probable contract commitments for the UK, Italy, Spain and France with the probable and possible receipt terminal capacity for those countries. For Italy, Spain and France the probable terminal capacity additions approximately match the contract volumes that were shown in Figure 8.5. However, the UK terminal expansion plans are for a much larger volume than those contract dedications. This is attributable to two factors – (1) there is a significant amount of supply 'gaming' going on in the UK as it is in the USA, and (2) some of the contract volumes for one of the large terminal sponsors, BG, is classed as 'destination unspecified' in Figure 8.5 based on trade press reports.

The present expectation is that decline in availability of North Sea gas, together with growth in UK demand will create a substantial gap in gas supply by the end of the decade. The LNG terminal expansions outlined in Figures 8.5 and 8.7 assume that the proposals will go forward by the year 2010. However, the demand gap is being challenged by pipeline projects from Norway, the Continent and possibly Russia[9] and the LNG imports could well be delayed beyond 2010.

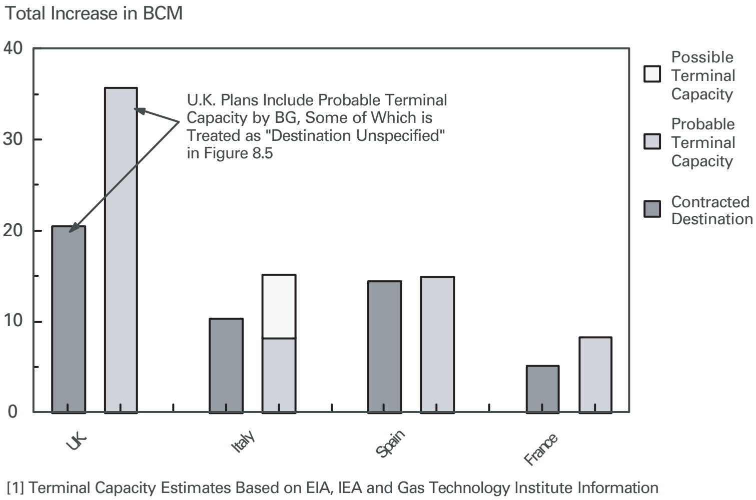


Figure 8.7: Increased Contract Deliveries to Europe Between 2003 and 2010

Source: Author's estimates

There have been complex negotiations between the UK terminal sponsors and Ofgem, the UK regulatory agency over the issue of third-party access. In February 2004, Ofgem granted a 25-year exemption from the European Union requirement that the terminals must provide open access for third parties.[10]

Italy has had some problems with terminal siting, similar to those that have plagued the United States. The Italian terminal estimates in Figure 8.7 thus include some proposals that may not survive the approval process. In addition to the European expansion projects shown in Figure 8.7, there is one additional project that has been proposed for Aliaga in Turkey. This project has been stalled in part because of Turkish supply over commitments.

8.6 Asia

The two largest LNG importers – Japan and Korea – have a long history of LNG trade. Thus it is not surprising that a substantial portion of their contract volumes are coming up for expiration between now and 2010. As a result both countries show a negative change in net contract commitments over the decade. That clearly does not imply that there will be no growth in their markets nor that they will not need expanded terminal capacity in order to accommodate growth.

Figure 8.8 compares the incremental contract commitments for the main Asian markets with published estimates of new terminal capacity. However, it also includes estimates of demand growth for Japan and Korea derived from the EIA's *International Energy Outlook 2003* in order to place some demand perspective on those two markets.

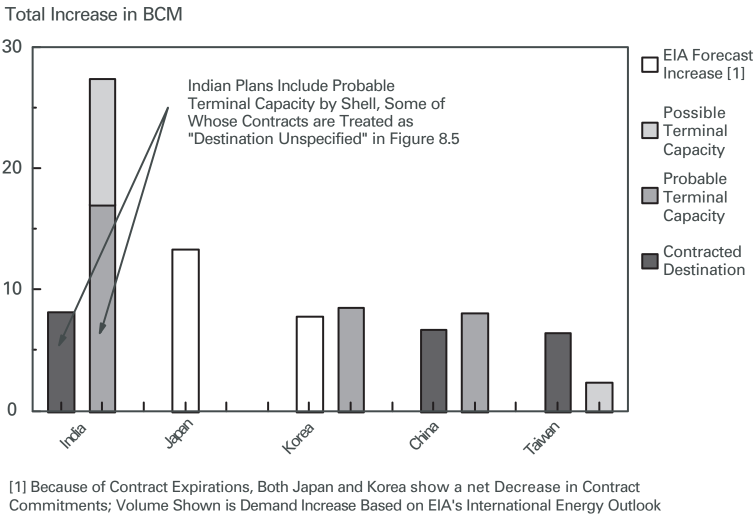


Figure 8.8: Increased Contract Deliveries to Asia Between 2003 and 2010

Source: Author's estimates

In the estimates of Figure 8.8, India has surpassed both Japan and Korea as growth markets for LNG. India has proved to be something of an enigma. Absent geopolitical concerns, pipeline supply to India is economically attractive, particularly for reaching the interior of the country. But from the west and north, Iranian supplies would have to transit Pakistan and those from Turkmenistan would also have to transit Afghanistan. Supplies from Bangladesh in the east are also politically complicated. As a result, LNG seems most likely to capture the early growth in Indian gas demand.

There was a great deal of early enthusiasm for new LNG projects following Enron's sponsorship of the controversial Dabhol power generation project. The plant's initial startup was to be based on naphtha firing, but was later to be based on imported LNG.

At one point there were as many as eight proposed LNG terminals for India, but enthusiasm has now cooled somewhat. The total number of possible projects included in Figure 8.8 has been reduced to those that now seem reasonable targets for expansion. This somewhat less optimistic outlook is both a result of the failure of Enron's Dabhol project and of difficulties in getting financial guarantees from power generation customers. The successful startup of Petronet's Daheej terminal this year followed by Shell's Hazira terminal (both in Gujerat) may well be the forerunner of a new wave of activity in LNG in India.

Despite the absence of a net increase in contract commitments through 2010, Japan will clearly need additional terminal capacity during the period. From trade press reports, this is most likely to come in the form of expansion at existing sites. Korea also shows a net decrease in contract commitments over the decade as a result of contract expirations. Korea's outlook is also clouded by uncertainty around the potential liberalisation of the gas industry and its effect on the government monopoly, Kogas. The one probable terminal is that of Pohang Iron and Steel at Kwangyang.

China has also proved to be an enigmatic potential customer for LNG since it has a number of pipeline supply options. It has significant domestic gas supplies in the Ordos Basin and in Sichuan near its eastern markets, but much of its resource potential is located in the far west in the Tarim Basin. These western domestic sources are being linked to the major Shanghai regional market via the ambitious East-West pipeline. In addition, China has been discussing the possibility of importing gas from the Kovytka field near Irkutsk in East Siberia. These pipeline projects could preempt early demand growth from LNG if markets do not develop as rapidly as Chinese planners expect.

Nevertheless, China has two planned terminals at Guangdong in the south and at Fujian nearer Shanghai. Another three terminals are under consideration on the east coast.

Taiwan has one new terminal under consideration that would serve a Taipower expansion, but it has been delayed. Elsewhere in Asia, the Philippines has considered a new terminal at Mariveles to serve power generation. Indonesia has also considered an LNG import terminal to serve a market in West Java as an alternative to pipeline supply.

Notes

1. *World Gas Intelligence*, 22 January 2003, p.1.
2. Decision in Federal Energy Regulatory Commission Docket CP-374-000 dated 18 December 2002.
3. *World Gas Intelligence*, 28 January 2004, p.5.
4. See Website – www.conversiongas.com
5. *World Gas Intelligence*, 17 September 2003, p.8.
6. 'The Global Liquefied Natural Gas Market: Status & Outlook', Energy Information Administration, December 2003.
7. Ibid., p.28. (Note: Includes imports through new terminals only excluding existing four terminals).
8. EIA treats LNG imports into California via Mexico as Mexican imports: data via personal communication from EIA.
9. *World Gas Intelligence*, 31 March 2004, p.8.
10. *World Gas Intelligence*, 25 February 2004, p.3.

APPENDIX A

Capacity Definitions

Liquefaction Plants – Liquefaction plant modules are called ‘trains’ and their capacities are quoted in metric tons of liquid. One 4 million ton train produces about 5.52 BCM per year.

Tankers – Tanker capacities are quoted in cubic metres of liquid cargo. A 138,000 cubic metre tanker holds about 0.084 BCM of gas.

Conversion Factors

FROM	Metric Ton of LNG	Cubic Metre of LNG	Cubic Metre of Natural Gas	Cubic Foot of Natural Gas
Metric Ton of LNG	1.00	2.19	1,336	47,260
Cubic metre of LNG	0.46	1.00	610	21,533
Cubic Foot of LNG	0.012	0.028	17.08	610